B-Level

WITH EXISTING TECHNIQUES

CONVENTIONAL RIG USED TO DRILL 46-INCH HOLES

Page 85

UNIVERSITY OF MICHIGAN
FEB 9 1960
SCIENCE LIBRARY

PRODUCTION PRACTICES MANUAL

PRODUCING EQUIPMENT FOR NATURAL GAS WELLS

PART 2

Page 51

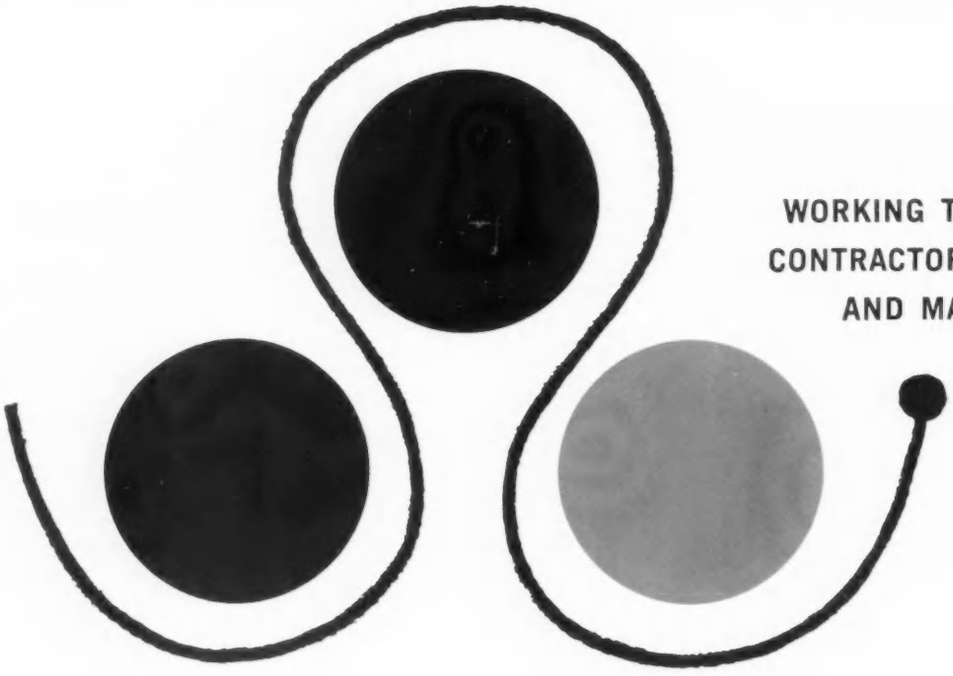
WORLD OIL

SPECIALIZED FOR EXPLORATION, DRILLING AND PRODUCTION OPERATIONS AND MANAGEMENT

FEBRUARY 1, 1960

Rotary drilling in Iran 77
Natural gas bill in 1960? 78
How to analyze bioherms 82
Improve your mud control 94

SUBSCRIPTION PRICE $2 PER YEAR • SINGLE COPY PRICE 50 CENTS



WORKING TOGETHER... CONTRACTOR, PRODUCER, AND MAGCOBAR

plan mud programs for pay and profit

High drilling costs can be cut by efficient use of drilling fluids. The right drilling chemicals, **used right** by Magcobar engineers, can help increase penetration rates, save on trips and bits, reduce materials needed, and save on equipment and manpower.

But, to make sure that the mud program is the most efficient, it must be planned from the beginning. And, because it must deal with so many specifics, it can be developed only with the close cooperation of producer, contractor, and Magcobar engineer. A sound mud program must be based on product performance, formations to be drilled, and, very important, type of equipment to be used.

By working together, a planned mud program can be developed to make full use of the money-saving advantages of Magcobar Technology. This Technology formulates special drilling fluids to reduce or prevent damage to the pay, resulting in quicker completion, higher production, and less need for expensive stimulation work. Magcobar Technology can help you as a contractor to drill wells more cheaply, can help you as a producer to have better wells. Drill your next wells with Planned Mud Programs with Magcobar.

ANOTHER **WELL DONE** WITH MAGCOBAR TECHNOLOGY

Magcobar
Complete
DRILLING MUD SERVICE

MAGNET COVE BARIUM CORPORATION HOUSTON

Established 1916 as The OIL WEEKLY®

VOLUME 150, NO. 2 FEBRUARY 1, 1960

WORLD OIL

A Gulf Publishing Company Publication

SPECIALIZED FOR EXPLORATION, DRILLING AND PRODUCING OPERATIONS AND MANAGEMENT

PRODUCTION PRACTICES MANUAL

Producing equipment for natural gas wells

5. The glycol dehydrator p. 51
George J. Mapes

6. The short cycle hydrocarbon recovery unit p. 59
R. W. Scott

7. The ammonia absorption refrigeration unit p. 70
J. Roger Heumann

To be concluded in March

CURRENT OUTLOOK

Looking ahead 13
Editorial: Challenge for the 60s 17
The changing panorama 25
Petroleum trends in the United States 25
Drilling activities 29
Natural gas in 1960
Roger L. Conkling 78

EXPLORATION

How to analyze bioherms in Williston Basin
Paul J. Lewis 82
Photogeology giving rapid coverage in Four Corners
Marshall S. Wright, Jr. 104

DRILLING

Conventional rig drills 46-inch holes in New Mexico
Gilbert M. Wilson 85
Thinning agents control flow properties of mud
William C. Browning 94

PRODUCTION

How to improve your gas lift installations (Part 7—Conclusion)
H. W. Winkler 89

INTERNATIONAL

NIOC charts Qum area drilling
T. B. Young 77

DEPARTMENTS

A QUICK LOOK at this issue 4
Practical operating hints 36
Your industry at work 110
Men in the industry 112
Deaths 115
Who's meeting where 117
Associations 118
Suppliers' notes 121
Classified advertising 128
Trading post 128
Squeaks from the bullwheel 131
What's new in equipment 134
New equipment catalogs and literature 150
Advertisers' index 152

For a "Quick Look" at this issue, turn the page

WORLD OIL published every month except semi-monthly in February and August. Second class postage paid at Houston, Texas.

a QUICK LOOK at this issue . . .

BUSY OIL MEN: To help you put first things first, scan these time-saving digests on this and the following pages, checking ☑ those you want to read first.

PRODUCTION PRACTICES MANUAL

☐ **The glycol dehydrator . . .** Glycol dehydration units are widely used for field gas drying applications. Installation costs are relatively low and operating costs are comparable with other types of field units. In addition, pressure drop through the glycol unit is low; consequently, low-pressure gas streams can be handled with ease. This section of the Production Practices Manual discusses the various items of equipment which make up the glycol dehydration unit, including both countercurrent and concurrent flow absorbers. . . . . **Page 51**

☐ **The short cycle hydrocarbon recovery unit . . .** Many gas producers are installing short cycle adsorption units to process lean field gas streams. The unit utilizes a bed of adsorbent material (desiccant) to dehydrate natural gas and recover heavy hydrocarbons which previously were lost into the sales gas line. Hydrocarbons are adsorbed on the desiccant by passing the wet gas stream through a bed of the desiccant material. After the heavy components are adsorbed, the main gas stream is switched to another adsorber tower and a stream of hot regeneration gas is passed through the "wet" tower. The hot gas carries the vaporized components for the adsorber, through cooling equipment where they are condensed and finally into a separator where they are recovered as a stock tank liquid. The additional recovery realized will pay out the cost of all required equipment. This article describes the units as to type of regeneration gas system, equipment and trouble-shooting information. Advantages and disadvantages are listed. . . . . **Page 59**

☐ **The ammonia absorption refrigeration unit . . .** Low temperature separation techniques using the ammonia absorption refrigeration unit are ideal for field processing rich gas streams (gas lift and reservoir injection gas, low-pressure gas-condensate streams, compressed treater gas, etc.). Present installations of high-pressure low-temperature separation units using a choke can be converted for use with an ammonia absorption unit when wellhead pressures decline and will no longer provide sufficient cooling for proper operation. The ammonia unit substitutes only for the choke and the remainder of the LTS equipment remains unchanged. For complete, easy-to-understand information on the ammonia absorption refrigeration unit, turn to. . . . . **Page 70**

☐ **Natural gas in 1960 . . .** There is little chance for decisions on critical natural gas issues during this presidential election year. But look for plenty of fireworks in 1961. For a timely, authoritative review and analysis of such important issues as the National Fuels Policy, Phillips Decision, conservation, and cost allocations, turn to . . . . . **Page 78**

☐ **How to analyze bioherms in Williston Basin . . .** Determination of distinct bioherm facies is crucial in the search for oil in the Mission Canyon (Mississippian) formation. Potential reservoirs are the flank facies of crinoid-bryozoan calcirudities and calcarenities, exhibiting thicker development on the lagoonal than on the marine side. Density differences and velocity variations of different facies may provide an approach by seismograph to augment subsurface studies. . . . . **Page 82**

What they are saying about the Production

IN JANUARY, WORLD OIL published the first of a three-part series that describes completely the equipment used in producing natural gas. Since this subject had never before been covered so thoroughly by any oil industry publication, the WORLD OIL staff naturally was concerned about its acceptance.

That concern was short-lived, for response was immediate and enthusiastic. Following are just a few examples of the comments received:

". . . We sincerely hope the Production Practices Manual will be combined into book form. This information is sorely needed, both in the industry and in engineering schools."

". . . Performs a great service for the industry."

•

". . . I wish to extend my sincere congratulations on the Production Manual, it is the best presentation I have seen on the subject. Such a manual has been needed in the industry for some time, and I am looking forward to seeing it bound into one book."

•

Be sure to read the second part of the Manual, starting on Page 51, for a complete, fully illustrated description of glycol dehydrators, short cycle dry desiccant dehydrators and ammonia refrigeration units as applied to low temperature separation.

Watch for the Exploration issue in April . . .

☐ **Standard rig drills 46-inch holes in New Mexico . . .** Increasing demand for large diameter holes encourages one contractor to adapt a standard rig, use unusual techniques, to handle special problems involved. For a case history of a recent 46-inch hole job, turn to ..... Page 85

☐ **Here's how to improve your gas lift installations (Part 7—Conclusion) . . .** Surface equipment used to control injection gas is an important operating factor in many gas lift installations. Some wells cannot be lifted while others operate inefficiently unless proper injection gas controls are installed. This final article of a series discusses control pilots used to regulate input gas for several types of gas lift installations. Dual wells with a common injection gas source are included ..... Page 89

☐ **Thinning agents control flow properties of mud . . .** The author points out that an economic drilling program is one that costs least in chemicals, equipment and time. The basis for this is a drilling fluid in which bentonites do not swell. Thinner action is a subject of colloid chemistry. Bentonite swells on addition of water due to electrolytes and proper chemical additives will prevent swelling and flocculation. Graphs show the effects on muds of varying character by additions of caustic soda, lime and calcium lignosulfonates. . . Page 94

☐ **Photogeology giving rapid coverage in Four Corners . . .** The Four Corners area is susceptible to quick and effective aerial photographic mapping and aerial photogeologic coverage. Color photogeologic interpretation works unusually well there, too. The remoteness of the area and the need for prompt coverage for oil and mining companies operating there has caused development of a high level of competence in acquiring and geologically interpreting aerial photographic mosaics ..... Page 104

Practices Manual

More Coming in March

The last part of the series will be published next month, and will contain a detailed description of:

- Indirect Flow Line Heaters
- Instrumentation and Control for Field Units
- Three-Phase (Oil, Gas, Water) Separation

Save the three parts of this series. They represent the first Production Practices Manual to be published that describes completely the equipment used in producing natural gas—written especially for the production man.

Oil Industry In Brief

Here are the latest industry trends, revealed by WORLD OIL and industry research:

On the plus side

Demand to increase. BuMines predicts total petroleum demand will increase 3.6 percent to 10,080,000 barrels daily in 1960 . . . See Page 25.

Inventories improve. Current stocks of crude oil and major refined products appear reasonable in relation to demand . . . See Page 25.

More wells in '60. WORLD OIL forecasts 49,020 wells will be drilled this year, up 1.4 percent over 1958.

Wildcats increase. Total wildcats increased 1.1 percent, from 9,799 in 1958 to 9,908 last year . . . See Page 29.

Footage up in '59. Operators drilled 202.5 million feet of hole last year, up 7.5 million feet or 3.8 percent over 1958 . . . See Page 29.

On the minus side

Imports up. Total imports averaged 1.76 million barrels daily last year, up 3.6 percent over 1958—and will go up 2.2 percent more in 1960, to 1.8 million barrels daily . . . See Page 25.

Exports down. Export demand was down 23,000 barrels or 12 percent in averaging 243,000 barrels per day during 1959 . . . See Page 25.

Dollar shrinks again. Compared with 1939 purchasing power, today's dollar is worth only 47.3 cents—and is expected to drop to 46.5 cents in 1960 . . . See Page 17.

Rig totals drop. Rigs of all types operating in the U.S. on December 31 totaled 4,094, the lowest number since last February—and 351 rigs or 7.9 percent under the same date in 1958 . . . See Page 29.

. . . and a bonus book February 15 . . . . .

New features added

TWO WEEKS from now WORLD OIL will publish its new, improved annual Forecast-Review Issue, dated February 15, 1960.

The issue will forecast what lies ahead in 1960 in all phases of the oil and gas industries. Predictions will be based on extensive and careful surveys and studies. Reports will show also what happened in 1959 and compare those results with earlier periods.

L. J. Logan

The February 15, 1960 issue will be even more comprehensive than like issues of previous years.

Assuring this improvement, in particular, will be three new, high-interest features. They will be presented in addition to retaining almost all of the established, valuable features of other recent years.

The three new features are as follows:

• **Outlook for U.S. exploration in 1960.** Timely reports and key maps will point out significant exploration and drilling to be expected in all states and districts.

• **New drilling equipment and methods.** A discussion of the progress made in 1959 in solving drilling problems through use of new methods and new improved drilling equipment, illustrated with photographs, drawings, etc.

• **New production methods.** This article will show what progress was made in 1959 in working out new and improved techniques in production operations. It will describe latest methods in well completions, perforating, formation fracturing, artificial lift, gas-oil separation, storage, etc.

Those added, timely, practical features will liven up the issue and widen reader interest.

You can confidently expect much of interest and value in the Forecast-Review Issue, February 15, 1960.

L. J. Logan

Index available

ORDERS ARE NOW being taken for the Annual WORLD OIL Editorial Index. This service to WORLD OIL readers covers the 14 issues published during 1959—and is bound in convenient pamphlet form. It will be sent free to all WORLD OIL readers requesting a copy.

Address your order to: Librarian, Gulf Publishing Company, Post Office Box 2608, Houston 1, Texas. Or if you prefer, use the convenient Reader Service Blue Postcard just inside the back cover of this and every issue of WORLD OIL. Check the square indicated, fill in your name and address, and drop the postage-paid card in the mail.

WORLD OIL

RAY L. DUDLEY, Founder, 1891-1957

WILLIAM G. DUDLEY.....Publisher
DONALD E. KLIEWER.....Editorial Director
L. J. LOGAN.....Associate Editor
DON E. LAMBERT.....Associate Editor, Current Outlook
WALLACE FITZGERALD.....Managing Editor
ROBERT W. SCOTT.....Engineering Editor
JACK F. EARL.....Engineering Editor
HARRISON T. BRUNDAGE.....Exploration Editor
GILBERT M. WILSON.....Western District Editor
ANTHONY GIBBON.....Mid-Continent District Editor
JACK COCKERHAM.....Presentation Editor
FERN C. REED.....Editorial Assistant
JOHN BRADLEY.....Editorial Assistant
ROBERT C. GRIFFIN.....Editorial Assistant
DOLORES REYNOLDS.....Editorial Assistant
EUNICE M. OKONESKI.....Librarian

WORLD OIL
Is Published By
GULF PUBLISHING COMPANY

EXECUTIVE OFFICES: 3301 BUFFALO DRIVE, HOUSTON
Cable Address, Gulfpubco, Houston
World's Largest Specialized Publishers to the Oil Industries

WILLIAM G. DUDLEY.....President
TOM W. NELSON.....Vice Pres.-Gen. Mgr.
R. M. DE SOMBRE.....Vice Pres.-Asst. Gen. Mgr.
NELSON L. BIGELOW.....Vice President Sales
MRS. RAY L. DUDLEY.....Vice President
P. J. AUCOIN.....Treasurer

ADVERTISING

Nelson L. Bigelow, Advertising Sales Manager, Houston
HOUSTON (1)—P.O. Box 2608
Charles Wyatt, C. A. Davis, Phone JAckson 9-4301
NEW YORK (17)—250 PARK AVENUE
Sam Sorrell, Phone YUkon 6-6558
CLEVELAND (16)—20800 CENTER RIDGE ROAD
Bill Westfall, Phone EDison 3-1650
CHICAGO (46)—6039 N. CICERO AVENUE
Al Seymour, Phone AVenue 2-4333
LOS ANGELES—1810 FAIR OAKS AVE., SOUTH PASADENA
Jay Curts, Jim Merrill, Phone MUrray 2-3518
TULSA (3)—916 ENTERPRISE BUILDING
Jim Isaacks, Phone LUther 2-9211
DALLAS (8)—1808 SYLVAN DRIVE
Ed Thompson, Phone RIverside 7-7344
LONDON, ENGLAND—120 MOORGATE, E. C. 2
Frank Chambers, Agent, Phone MOnarch 5661
HERFORD/W., GERMANY—ORTSIEKERWEG 59A
Gerd Hinske, Phone 4990

Advertising rates on application.

SUBSCRIPTIONS

R. B. Reilly, Circulation Manager, P. O. Box 2608, Houston 1, Texas. U.S.A. Single copies 50 cents (except special issues). Double prices for single copies more than a year old. Subscription rates: both foreign and domestic $2 a year.

Copyright 1960 by Gulf Publishing Company. WORLD OIL and THE OIL WEEKLY are registered trademarks of Gulf Publishing Company, Houston, Texas

Postmaster. Send notification (Form 3579) regarding undeliverable magazines to WORLD OIL, Box 2608, Houston 1, Texas.

GPC PUBLICATIONS

WORLD OIL (formerly The Oil Weekly) and The COMPOSITE CATALOG for the drilling-producing industry.
PIPE LINE INDUSTRY and The PIPE LINE CATALOG for the oil and gas pipe line industry.
PETROLEUM REFINER and The REFINERY CATALOG for the oil, gas and petrochemical processing industry.

Indexed by Industrial Arts Index and Engineering Index

Looking Ahead

1960 forecast: U.S. oil and gas industry will drill 1.4 percent more wells—1.8 percent more feet of hole . . . World Oil survey of several hundred operators reveals following outlook for 1960:

- 48,328 new wells, up 692 wells, or 1.4 percent over 1958. Of the total, 17,605 wells, or 36.4 percent, will be drilled in Texas.
- 206,162,000 feet of hole will be drilled, up 3.6 million feet, or 1.8 percent from 1958.

Gulf sets drilling record . . . Using Kermac's offshore rig 46, Gulf Oil recently drilled from spud to 10,000 feet in 4 days, 22 hours in Timbalier Bay field off the Louisiana coast (8-10 days is considered average in the area). What is believed to be new time record included setting 2,500 feet of 10¾-inch surface casing, normal waiting on cement and nippling up. Actual rotating time consumed only 57 hours.

Precedent-shattering performance was made possible by excellent drilling crew cooperation, plus use of high bit weights, fast rpm's, maximum efficiency hydraulic program, tight mud control.

New union contract may curb oil industry steel purchases . . . Predictions are that steel prices will go up another $4-$5 per ton in '60 to offset steel's $1 billion boost in labor costs. Result: Look for oil industry trend to slim hole drilling, single and multiple tubingless completions to gain momentum. Also greater use of imported steel, aluminum and plastic pipe may well be in the offing.

Big Algerian frac job to start soon . . . Equipment was en route in January for first hydraulic fracturing job in Algeria's Hassi-Messaoud oil field, where 300 feet of Cambro-Ordovician pay sandstone (about 11,000 feet) often shows 10 millidarcys or less permeability. Humorous paradox will occur when half-ton of high permeability packaged sand from the United States is unpacked by Arab helpers in the middle of the Sahara, with almost nothing but sand to be seen for miles.

World rig totals may soon be available . . . If International Oil Scouts Association approves plan at summer meeting, the group will join American Association of Oilwell Drilling Contractors in project to determine number of active drilling rigs operating throughout the world. **In another cooperative project,** I.O.S.A. will work for the first time with Society of Petroleum Engineers in preparing 1960 edition of 28-year-old "International Oil and Gas Developments," which includes world-wide oil and gas field statistics.

Washington developments . . . Considerable surprise, and concern, was expressed over omission of expected Administration backing for natural gas decontrol bill in President's budget message, particularly since there appears to be almost unanimous support for such legislation among Cabinet members . . . **However, Texas Independent Producers and Royalty Owners Association (6,500 strong) refuses to lose hope**—recently adopted framework for a new gas bill to make sure the decontrol issue stays very much alive . . . **Interior Department reports U.S. crude production increased 5 percent** to 2.6 million barrels during 1959, while crude oil prices dropped 7 cents to an average of $2.94 per barrel.

HERE'S ANOTHER REASON WHY
FORD TRUCKS ARE YOUR BEST BUY!

"REGARDLESS OF THE TERRAIN— MUD FIELDS... SAND... SWAMP BEDS—WE DEPEND ON OUR FORDS TO DO THE TOUGHEST JOBS"

SAYS ARNOLD J. LEWIS, MAINTENANCE FOREMAN, FARM BUREAU OIL COMPANY, INC., MT. VERNON, INDIANA

"Our trucks can be found anywhere within a 250-mile radius of Mt. Vernon transporting men and equipment needed for every phase of the oil business. We usually put our 28 Ford Trucks on the toughest jobs because we can depend on them to keep going even if they have to winch themselves out.

"The performance of our Fords is truly outstanding, when you consider that many of our jobs take us along river banks and through plowed fields with mud axle-deep.

"The engines are used just as much for winching and driving other equipment during field operations as they are for highway driving. In two years we get up to 140,000 engine miles on our Fords before we trade them in. During that time we change the oil and oil filter every 2,000 miles and seldom add any oil between changes.

FORD F-600 shown above has a special utility bed designed and built in the Farm Bureau Oil Co. shop. It features a power driven pipe-threading attachment, heavy-duty winch, gin poles, headache rack, rolling tailboard, two-way radio plus both arc and gas welding equipment.

FORD TRUCKS

Challenge for the '60s

IF A TWO-DECADE trend is an indication, three disturbing predictions can be made for the 1960s:

Our federal budget will continue to soar skyward.

Big labor will keep on using its political power to pad its pockets.

As a result, inflation will eat deeper into the U.S. economy—the value of the dollar will continue to decline. But, it can't keep on declining indefinitely. And this brings up a highly debatable question. How long can we continue to sweeten our personal and federal coffers without seriously weakening the nation's economic position throughout the world?

Let's take a look at where we stand now on these three economic bellwethers.

> *"There comes a time in the life of each of us when we must face up to the fact that we have to live within our means, when the prospect of getting more money from the boss—or from customers—is pretty dim, and when we simply have to cut our pattern to our cloth."* Roger M. Blough, Chairman, United States Steel Corporation.

President Eisenhower has requested a $79.8 billion budget for the 1960-61 fiscal year—8½ times the $9 billion budget of 1940 and double the $39.6 billion spent in 1950.

The steel unions have won another round of wage increases—to start next December and continue until the middle of 1962. Government and labor spokesmen claim the agreement has slowed the inflationary spiral because wages will increase 3½ to 3¾ percent per year, compared with an average of 8 percent for the past 20 years. During the past two decades, steel's employment costs went up an average of four times the increase in shipments per man-hour.

Similar increases are expected in other industries. Thus, new price hikes in steel and other products can be expected.

Today's dollar, compared with 20 years ago, is worth 47.3 cents—on the basis of what it will buy as measured by the Consumer Price Index of the Bureau of Labor Statistics. The dollar a year from now is expected to decline to 46.5 cents.

On the basis of the above predictions and supporting statistics, our nation can ill afford even a slower inflationary spiral even though our government and labor leaders consider this achievement as a feather in their cap. This statement is substantiated, both by our declining influence as a competitor in the world market and by the observations of industrialists overseas.

Oil and steel are two good examples of our changing position in world trade. Twenty years ago, the United States exported 72.1 million barrels of crude oil, and imported only 34.1 million barrels. In 1958, the United States exported only 4.3 million barrels, while importing 383.7 million.

In 1958, the United States exported $238 million worth of steel mill products, and imported $161 million worth. Last year, exports dropped to $165 million, while imports increased to $191 million.

Meanwhile, economists in other nations have stated recently that even though U.S. business will improve during 1960, the dollar is becoming weaker and the U.S. position in world markets is declining. They agree that Russia is making some progress in its announced economic war with the United States.

In the light of these facts, it would seem logical for all of us to adopt one firm resolution for the next decade —make a lie of the three predictions.

Although increased military spending is necessary to maintain national security, keep a tight rein on every aspect of the federal budget—keep it within the limits of the national debt and the taxpayers' pocketbook. Increase productivity to keep pace with higher earnings. Stabilize, and if possible, increase the value of the dollar.

This is the big challenge of the 60s for industry, government and labor.

Two kinds of wire rope for a $850,000 rotary:

The most expensive or THE BEST

This kind of investment precludes anything but the best. And, *anything but the best* can turn out to be the most expensive. Bargain hunting for "Economy" ropes when you lay out this kind of money is akin to putting five cent shoe laces in a pair of $40.00 shoes. Fool around with low grade ropes and you run into high grade troubles. On the other hand, a rope like Roebling Royal Blue can help protect your investment by *staying on the job.*

Here's why: Royal Blue is made from the toughest rope wire ever produced—Type 1105, Extra High-Strength Improved Plow Steel. It is a preformed rope and its resistance to abrasion, fatigue, impact, crushing and shock is very special. Thus, with Royal Blue, you're working with an extremely rugged and flexible rope . . . a rope that has 15% more catalog strength than standard rope.

When it comes to $850,000 for a Rotary, you'll do very well to have your Roebling Distributor come to you. He'll show you the difference between the most expensive rope and the *best.* You can get any further information you want from Roebling's Wire Rope Division, Trenton 2, New Jersey.

ROEBLING

Branch Offices in Principal Cities
John A. Roebling's Sons Division • The Colorado Fuel and Iron Corporation

Better demand will aid industry in 1960

THE INDUSTRY entered 1960 in a relatively favorable situation. Increased demand for petroleum products was in prospect in the new year. New supplies of oils were being made to fit market requirements. Stocks of crude oil and major refined products appeared reasonable in relation to current and prospective demand.

Demand in 1960. Total demand for petroleum in 1960 will average 10,080,000 barrels daily, a new record and more than in 1959 by 370,000 barrels daily or 3.8 percent, the Bureau of Mines has forecast.

Increases for major products will include 3.1 percent for gasoline, 3.8 percent for distillate fuel oil, and 2.2 percent for residual fuel oil. Kerosine will show a slight decrease.

The increases will reflect similar gains in domestic consumption, as exports are expected to be down slightly.

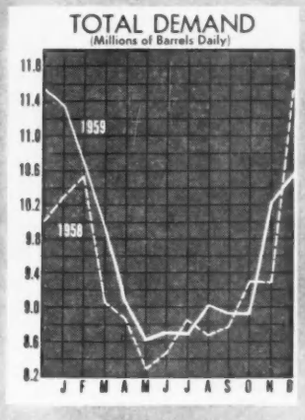
Stocks in 1960. The bureau assumed that crude stocks would show no net change in 1960. It estimated that the industry would expand product stocks by the moderate amount of 23,000 barrels daily.

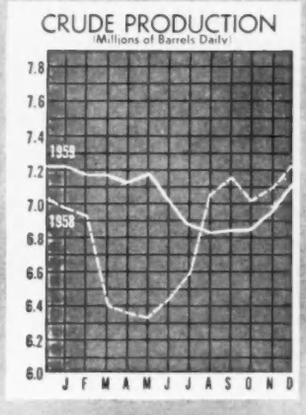
Supply in 1960. In meeting demand in 1960, imports will be increased to 1,799,000 barrels daily, a gain of 39,000 barrels or 2.2 percent, the bureau estimated. Shipments of both crude and products will be up somewhat.

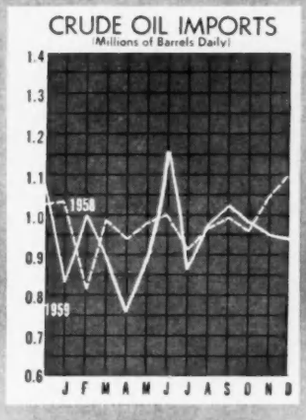
Production of natural gas liquids will be up to 877,000 barrels daily in 1960 from 870,000 in 1959, a gain of 7,000 barrels or 8/10 of 1 percent.

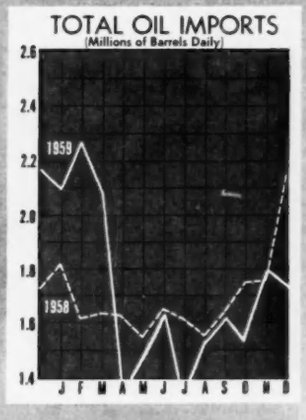
The remainder of supply will be furnished by crude oil production of 7,427,000 barrels daily in 1960, the bureau calculated. That will be an increase of 382,000 barrels daily or 4.9

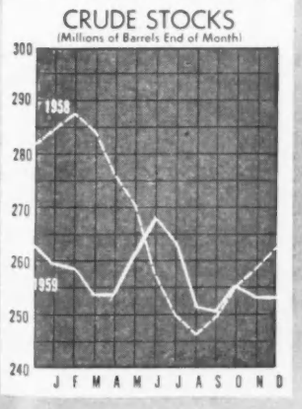
Petroleum Trends...

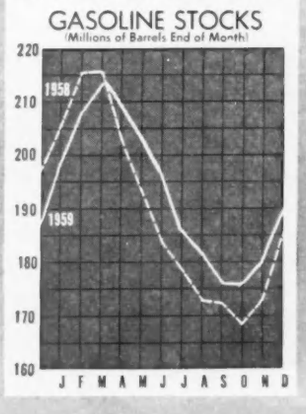


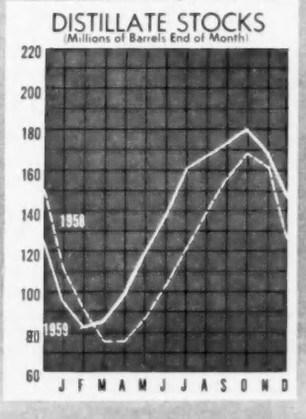


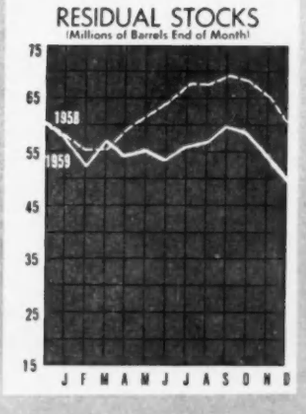












U. S. Petroleum Demand and Supply (Thous. Bbls. Daily)

ITEM	DECEMBER 1959	DECEMBER 1958	% Diff.	Nov. 1959	YEAR 1959	YEAR 1958	% Diff.
DEMAND							
All Oils, Total Demand	10,551	11,545	— 8.6	10,199	9,634	9,343	+ 3.1
Domestic Demand	10,311	11,322	— 8.9	9,969	9,391	9,067	+ 3.6
Export Demand	240	223	— 7.1	230	243	276	—12.0
Gasoline, Total Demand	3,926	3,950	— 0.6	3,941	4,103	3,960	+ 3.6
Distillate, Total Demand	2,535	3,179	—20.3	2,362	1,844	1,840	+ 0.2
Kerosine, Total Demand	526	573	— 8.2	399	306	314	— 2.6
Residual, Total Demand	1,810	2,084	—13.1	1,678	1,589	1,527	+ 4.1
Other Oils, Total Demand	1,754	1,759	— 0.3	1,819	1,792	1,702	+ 5.3
CHANGE IN STOCKS							
All Oil, Change in Stocks	—800	—1,371		—573	+41	—140	
NEW SUPPLY							
Total New Supply	9,751	10,174	— 4.2	9,626	9,673	9,126	+ 6.0
Domestic Production, Total	8,008	8,000	+ 0.1	7,835	7,915	7,505	+ 5.5
Crude Oil	7,102	7,136	— 0.5	6,935	7,042	6,709	+ 5.0
Natural Gas Liquids	906	864	+ 4.9	900	873	796	+ 9.7
Imports, Total	1,743	2,174	—19.8	1,791	1,758	1,697	+ 3.6
Refined Products	799	1,095	—27.0	841	802	744	+ 7.8
Crude Oil, Total	944	1,078	—12.4	950	956	953	+ 0.3
Crude, East Coast	656	826	—20.6	693	723	768	— 5.9
CRUDE RUNS							
Crude Runs to Stills	8,152	7,961	+ 2.4	7,917	7,989	7,606	+ 5.0
Domestic Crude	7,191	6,914	+ 4.0	6,901	7,031	6,660	+ 5.6
Foreign Crude	958	1,047	— 8.5	1,016	961	946	+ 1.6

U. S. Stocks of Oils (Million Bbls. at End of Month)

KIND OF OIL	TOTAL IN U.S. Dec. 1959	TOTAL IN U.S. Dec. 1958	% Diff.	TOTAL IN U.S. Nov. 1959	EAST OF CALIFORNIA Dec. 1959	EAST OF CALIFORNIA Dec. 1958	% Diff.	EAST OF CALIFORNIA Nov. 1959
All Oils	803.6	788.8	+ 1.9	828.4				
Crude Oil	253.6	262.7	— 3.5	252.6	219.8	222.5	— 1.2	219.3
Gasoline	189.0	186.8	+ 1.2	180.4	161.0	161.2	— 0.1	153.8
Distillate Fuel Oil	148.8	125.1	+18.9	165.9	135.4	112.4	+20.5	153.2
Kerosine	26.8	26.0	+ 3.1	30.9	26.3	25.7	+ 2.3	30.5
Residual Fuel	49.9	59.5	—16.1	54.9	27.9	27.4	+ 1.8	30.3
Other Oils	135.5	128.7	+ 5.3	143.7				

U. S. Crude Oil Production, by States (Thous. Bbls.)

STATE or DISTRICT	Daily Average for Month Dec. 1959	Dec. 1958	% Diff.	Nov. 1959	Total for Year 1959	1958	% Diff.
Alabama	15.8	15.5	+ 1.9	16.1	5,112	5,887	—13.2
Arkansas	59.1	77.9	—24.1	54.3	25,833	28,700	—10.0
California	837.7	849.8	— 0.3	837.3	307,344	314,429	— 2.3
Colorado	129.0	127.3	+ 1.3	127.8	46,193	48,309	— 4.4
Florida	1.3	1.2	+ 8.3	1.2	429	448	— 4.3
Illinois	218.0	227.5	— 4.2	218.8	78,493	82,125	— 4.4
Indiana	31.5	33.6	— 6.3	31.9	11,959	11,864	+ 0.8
Kansas	325.5	325.3	+ 0.1	326.5	119,438	118,188	+ 1.1
Kentucky	65.5	60.8	+ 7.7	68.9	26,471	17,509	+ 51.2
Louisiana	1,026.6	926.3	+ 12.8	1,033.8	354,446	312,070	+ 13.6
North Louisiana	113.6	110.7	+ 2.6	113.5	44,521	41,533	+ 7.2
South Louisiana	933.0	815.6	+ 14.4	920.3	309,925	270,537	+ 14.6
Michigan	33.9	27.3	+ 24.2	32.8	10,420	9,307	+ 11.9
Mississippi	146.2	116.1	+ 25.9	144.3	47,971	38,551	+ 24.4
Mo.-So. Dak.-Tenn.	0.5	0.1	+400.0	0.5	116	114	+ 1.7
Montana	80.5	79.6	+ 1.1	80.8	29,952	28,291	+ 5.9
Nebraska	63.4	56.7	+ 11.8	63.2	23,406	20,368	+ 14.9
Nev.-Wash.-Alaska-Ariz.	0.5	0.5		0.5	222	56	+296.4
New Mexico	296.0	280.7	+ 5.5	292.5	105,541	98,323	+ 7.3
Southeast New Mexico	255.4	248.6	+ 2.7	253.6	91,063	89,964	+ 1.2
Northwest New Mexico	40.6	32.1	+ 26.5	38.9	14,478	8,359	+ 73.2
New York	5.3	2.8	+ 89.3	5.4	1,974	1,664	+ 18.6
North Dakota	59.6	44.4	+ 34.2	50.6	17,962	14,141	+ 27.0
Ohio	11.8	16.2	— 27.2	12.9	5,444	6,260	— 13.0
Oklahoma	550.2	559.5	— 1.7	539.6	196,204	202,699	— 3.2
Pennsylvania	16.4	16.2	+ 1.2	16.9	6,081	6,678	— 8.9
Texas	2,641.8	2,851.9	— 7.4	2,529.6	981,379	940,706	+ 4.3
Dist. 1: South Central	45.8	46.3	— 1.1	45.9	16,580	16,883	— 1.8
Dist. 2: Middle Gulf	119.0	129.6	— 8.2	112.6	43,028	42,426	+ 1.4
Dist. 3: Upper Gulf	370.9	414.5	— 10.5	355.7	138,625	137,854	+ 0.6
Dist. 4: Lower Gulf	189.3	205.5	— 7.9	180.6	69,572	69,542	+ 0.1
Dist. 5: East Central	26.4	31.2	— 15.4	25.4	10,719	10,966	— 2.3
Dist. 6: Northeast	256.7	287.8	— 10.8	244.7	95,791	94,668	+ 1.2
Dist. 7-B: North Central	128.2	141.0	— 9.1	126.5	49,443	49,987	— 1.1
Dist. 7-C: West Central	128.3	142.9	— 10.2	122.1	46,737	48,776	— 4.2
Dist. 8: West	1,061.4	1,116.6	— 5.0	1,005.7	385,112	349,680	+ 10.1
Dist. 9: North	206.9	216.9	— 4.6	203.2	75,396	73,288	+ 2.9
Dist. 10: Panhandle	108.9	103.8	+ 4.9	107.2	39,354	36,688	+ 7.3
Utah	113.7	92.9	+ 22.4	100.3	39,961	34,386	+ 16.2
Virginia					5	6	— 16.7
West Virginia	5.9	5.6	+ 5.4	5.6	2,168	2,186	— 0.8
Wyoming	346.0	340.1	+ 1.7	342.9	125,845	115,572	+ 8.9
Total, U.S.	7,101.7	7,135.8	— 0.5	6,935.1	2,570,379	2,448,837	+ 5.0

Sources for above 3 tables: Bureau of Mines monthly reports, except last two months based on API and B. of M. weekly reports and WORLD OIL estimates, and all Texas districts from API.

percent over 7,045,000 daily in 1959, and will set a new record.

Crude runs to stills are projected to 8,356,000 barrels daily in 1960 from 8,000,000 daily in 1959, a 4.5 percent increase.

Demand in 1959. Total demand for all oils averaged 9,634,000 barrels daily in 1959, according to Bureau of Mines data for 10 months and American Petroleum Institute reports for November and December. That was an increase of 291,000 barrels or 3.1 percent over 1958.

Export demand was down 23,000 barrels or 12 percent in averaging 243,000 barrels per day in 1959. Domestic demand averaged 9,391,000 barrels daily in 1959, an increase of 324,000 barrels daily or 3.6 percent.

Total demand for gasoline averaged 4,103,000 barrels per day in 1959, an increase of 143,000 barrels daily or 3.6 percent. Residual fuel oil demand of 1,589,000 daily was up 62,000 barrels or 4.1 percent. Distillate fuel oil demand averaged 1,844,000 barrels daily, up 4,000 barrels or 2/10 of 1 percent. Kerosine demand of 306,000 barrels per day was off 8,000 barrels or 2.6 percent. Total demand for other oils averaged 1,792,000 barrels daily, an increase of 90,000 barrels or 5.3 percent.

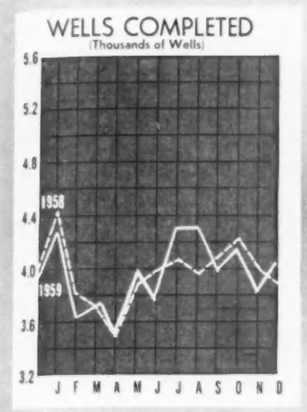
Supply in 1959. Total oil imports in 1959 averaged 1,758,000 barrels daily, up 61,000 barrels or 3.6 percent over 1958. Crude oil imports were up only 3,000 barrels or 3/10 of 1 percent to 956,000 daily in 1959. But product imports were up 58,000 barrels or 7.8 percent to 802,000 daily.

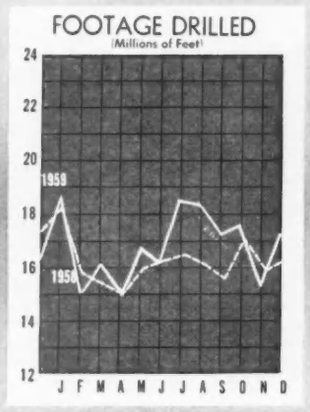
Production of crude oil averaged 7,042,000 barrels daily in 1959, up 333,000 barrels or 5.0 percent. Output of natural gas liquids averaged 873,000 barrels daily, a gain of 77,000 barrels or 9.7 percent.

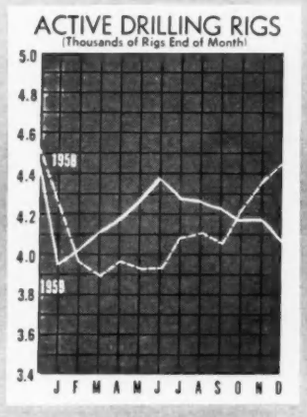
Crude runs to stills averaged 7,987,000 barrels per day in 1959, up 381,000 barrels or 5.0 percent.

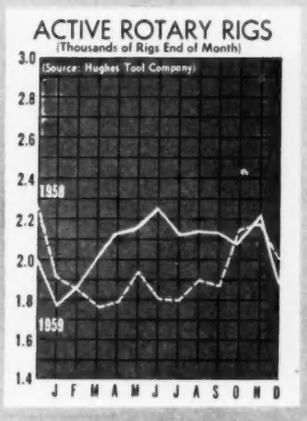
Stocks up in 1959. Stocks of all oils were increased in 1959 by 14.8 million barrels or 41,000 daily to 803.6 million. Withdrawals of 9.1 million barrels of crude and 9.6 million of residual fuel oil were more than offset by additions of 23.7 million barrels of distillate fuel oil, 2.2 million of gasoline, nearly 1 million of kerosine, and 6.8 million of other oils.

Drilling Activities...









1959 well completions drop slightly

NEW U.S. WELL completions declined for the third straight year in 1959, while total footage increased. Last year's drilling picture in brief:

New completions totaled 48,328 wells, down 342 wells or 0.7 percent from the 1958 total—and 10,090 wells less than the 58,418 wells completed during the record year of 1956.

Footage drilled totaled 202.5 million feet last year, up 7.5 million feet or 3.8 percent over 1958.

Total wildcats increased 1.1 percent, from 9,799 in 1958 to 9,908 last year.

December's new completions averaged 131 wells per day, up 4 percent over the daily average of 126 wells during November, and slightly higher than the December 1958 average of 130 wells per day.

Operators drilled an average of 555,000 feet of hole per day during December, up 8.8 percent over the November daily average.

Summary of U.S. Wildcat Drilling

ITEM	Dec. 1959	Nov. 1959	YEAR 1959	YEAR 1958	% Diff.
New Field Discoveries:					
Oil	65	61	713	743	— 4.0
Distillate	3	6	85	80	+ 6.2
Gas	24	40	281	226	+24.3
Total Discoveries	**92**	**107**	**1,079**	**1,049**	**+ 2.9**
Dry Wildcats	**801**	**727**	**8,829**	**8,750**	**+ 0.9**
Total Wildcats	**893**	**834**	**9,908**	**9,799**	**+ 1.1**
(Percent Productive)	10.3	12.8	10.9	10.7	.....
(Percent Dry)	89.7	87.2	89.1	89.3	.....

Summary of U.S. Drilling Activity

ITEM	Dec. 1959	Nov. 1959	YEAR 1959	YEAR 1958	% Diff.
New Wells Completed:					
Oil	1,946	1,805	24,043	24,048	— 0.0
Distillate	67	48	800	710	+12.7
Gas	374	381	4,131	4,332	— 4.6
Service	43	47	765	1,268	—39.7
Dry	1,645	1,490	18,589	18,312	+ 1.5
Total Wells	**4,075**	**3,771**	**48,328**	**48,670**	**— 0.7**
Footage Drilled (Millions of Feet)	**17.2**	**15.3**	**202.5**	**195.0**	**+ 3.8**

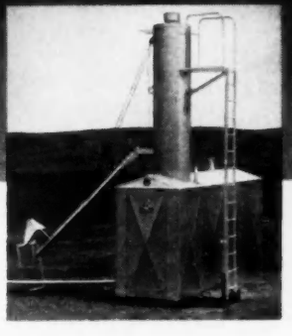
U.S. Drilling Activity in December and Years 1959 and 1958

STATE or DISTRICT	TOTAL NEW WELLS COMPLETED AND FOOTAGE DRILLED: DETAILS FOR DECEMBER, 1959 — Oil	Dist.	Gas	Dry	Service Wells	TOTAL NEW WELLS — Dec. 1959	Nov. 1959	Dec. 1958	Total Footage December 1959	DETAILS FOR YEARS 1959-1958 — NEW WELLS 1959	1958	Percent Diff	FOOTAGE 1959	1958	WILDCAT DRILLING IN YEARS 1959 AND 1958 — DETAILS FOR DEC., 1959 — Oil	Dist.	Gas	Dry	Total Wildcats	DETAILS FOR YEAR — Oil	Dist	Gas	Dry	TOTAL WILDCATS 1959	1958	DRILLING RIGS IN OPERATION (Rigging up, Drilling, Temp. Shut-Down) — Dec. 31, 1959	Nov. 30, 1959	Dec. 31, 1958
Alabama	7	....	....	2	....	9	9	11	80,478	108	85	+ 27.1	976,926	686,232	....	....	....	2	2	....	....	....	30	30	33	6	6	15
Alaska	1	....	2	1	....	4	2	....	31,185	14	....	....	141,670	....	....	....	....	1	1	1	....	1	7	9	....	7	6	....
Arkansas	33	....	1	24	....	58	69	101	184,927	814	852	— 4.5	2,728,131	2,848,849	....	....	....	8	8	7	....	10	112	129	164	45	45	52
California	71	....	10	52	3	136	143	134	664,371	1,487	1,432	+ 3.8	7,123,633	6,849,366	1	....	1	33	35	7	....	7	313	327	313	126	119	156
Colorado	11	....	7	46	....	64	28	61	333,247	726	850	— 14.6	3,818,603	4,412,384	2	....	....	35	37	25	....	16	349	390	473	42	45	60
Florida	....	....	....	1	....	1	2	1	6,437	10	7	+ 42.9	79,834	67,707	....	....	....	1	1	....	....	....	10	10	7	1	1	1
Illinois	63	....	2	55	....	120	213	118	257,662	2,032	2,302	— 11.7	4,496,314	5,259,711	....	....	2	25	27	11	....	2	486	499	589	324	336	294
Indiana	20	....	....	45	1	66	44	82	69,782	847	891	— 4.9	1,282,957	1,435,650	....	....	....	30	30	3	....	1	248	252	248	92	94	113
Kansas	172	....	22	190	3	387	351	344	1,374,387	3,831	3,759	+ 1.9	14,015,311	12,981,318	18	....	2	102	122	148	....	30	1,010	1,188	992	245	305	338
Kentucky	132	....	24	85	4	245	250	236	214,243	2,930	2,371	+ 23.6	2,646,843	2,454,401	....	....	....	8	8	10	....	....	79	89	75	180	200	95
Louisiana	171	22	27	139	....	359	295	304	2,532,496	3,831	3,508	+ 9.2	29,289,485	27,066,565	2	1	....	41	44	29	16	13	479	537	607	325	329	356
North Louisiana	81	....	17	69	....	167	144	121	610,595	1,543	1,389	+ 11.1	5,145,656	5,171,217	2	....	....	21	23	17	1	5	189	212	227	50	65	65
South Louisiana	90	22	10	70	....	192	151	183	1,921,901	2,288	2,119	+ 8.0	23,843,829	21,895,348	....	1	....	20	21	12	15	8	290	325	380	275	264	291
*Gulf of Mexico	31	6	1	13	....	51	26	36	495,729	474	487	— 2.7	4,867,623	4,702,522	....	1	....	1	2	2	4	4	26	36	40	58	48	44
Michigan	21	....	2	25	....	48	66	36	174,778	596	392	+ 52.0	1,866,192	1,123,455	....	....	1	15	16	4	....	5	158	167	131	115	95	86
Mississippi	29	4	3	40	....	76	45	64	745,956	669	428	+ 55.9	6,291,843	3,641,127	1	....	....	29	30	9	1	2	240	252	161	77	86	75
Missouri	....	....	....	....	....	....	2	1	....	14	16	— 12.5	12,901	16,167	....	....	....	....	....	1	....	....	10	11	9	3	2	....
Montana	23	....	....	21	....	44	25	25	205,563	342	306	+ 11.8	1,639,710	1,607,096	1	....	....	12	13	3	....	1	106	110	119	42	47	39
Nebraska	17	....	....	53	....	70	36	58	379,669	825	697	+ 18.4	4,872,812	4,163,621	3	....	....	37	40	39	....	....	338	377	328	25	20	30
New Mexico	91	....	33	43	....	167	196	141	713,744	1,819	1,970	— 7.7	7,580,624	9,107,964	3	....	5	25	33	34	1	31	213	279	275	173	167	154
Southeast	72	....	1	35	....	108	102	57	465,148	1,015	969	+ 4.7	4,691,142	4,835,379	3	....	....	21	24	25	....	5	159	189	179	98	95	83
Northwest	19	....	32	8	....	59	94	84	248,596	804	1,001	— 19.7	2,889,482	4,272,585	....	....	5	4	9	9	1	26	54	90	96	75	72	71
New York	12	....	2	4	6	24	23	23	43,710	278	215	+ 13.5	481,275	* 387,229	....	....	....	....	....	....	....	....	....	....	....	25	25	42
North Dakota	25	....	....	26	....	51	28	23	311,697	433	408	+ 6.1	2,741,670	2,642,398	3	....	....	13	16	16	....	....	67	83	120	25	22	34
Ohio	46	....	36	37	2	121	132	82	285,550	1,085	988	+ 9.8	2,761,713	2,582,097	2	....	1	4	7	8	....	8	25	41	13	210	212	228
Oklahoma	148	7	40	139	3	337	169	588	1,430,819	5,192	7,047	— 26.3	19,137,906	21,953,621	7	....	5	37	49	77	12	39	601	729	770	495	466	529
Pennsylvania	21	....	23	8	10	62	65	78	170,981	695	794	— 12.5	2,148,815	2,407,178	1	....	....	2	3	1	....	4	19	24	34	186	195	210
South Dakota	2	....	....	1	....	3	5	1	25,649	23	7	+228.6	168,360	33,649	....	....	....	1	1	3	....	....	11	14	7	5	3	3
Tennessee	....	....	....	....	....	....	15	4	....	107	30	+256.7	100,422	37,650	....	....	....	....	....	....	....	....	57	57	12	25	30	....
Texas	768	34	80	510	11	1,403	1,358	1,343	6,077,267	17,597	17,283	+ 1.8	77,636,405	73,280,859	18	2	5	281	306	249	54	96	3,426	3,825	3,969	971	1,021	1,181
Dist. 1: South Central	49	1	7	39	....	96	84	107	283,135	979	988	— 0.9	2,587,789	2,451,870	1	....	....	28	29	8	1	1	298	308	314	38	35	36
Dist. 2: Middle Gulf	13	5	6	25	....	49	70	56	310,193	786	699	+ 12.4	4,910,719	4,280,900	1	1	1	20	23	11	14	15	243	283	247	58	48	52
Dist. 3: Upper Gulf	40	16	7	44	....	107	92	123	704,877	1,190	1,295	— 8.1	8,439,430	8,366,026	2	1	....	24	27	11	24	9	243	287	354	96	106	113
*Gulf of Mexico	....	....	....	....	....	....	3	....	....	5	11	— 54.6	49,112	86,748	....	....	....	....	....	....	....	1	3	4	9	....	....	....
Dist. 4: Lower Gulf-S.W.	28	12	10	50	....	100	75	98	587,860	1,308	1,128	+ 16.0	7,115,371	5,861,401	1	....	1	34	36	16	12	11	371	410	463	64	74	85
*Gulf of Mexico	....	....	....	....	....	....	....	....	....	1	8	— 87.5	500	84,048	....	....	....	....	....	....	....	1	1	....	3	....	....	....
Dist. 5: East Central	3	....	2	17	....	22	15	15	124,705	162	194	— 16.5	874,843	736,388	....	....	....	15	15	2	....	2	73	77	111	8	15	14
Dist. 6: Northeast	42	....	4	31	....	77	71	73	450,145	840	839	+ 0.1	4,628,080	4,502,167	1	....	....	19	20	11	1	7	163	182	211	47	59	58
Dist. 7-B: North Central	74	....	8	87	2	171	192	152	591,840	2,392	2,132	+ 12.2	7,729,310	6,781,123	6	....	2	61	69	65	1	17	711	794	758	92	100	84
Dist. 7-C: West Central	20	....	3	27	1	51	58	41	210,504	749	748	+ 0.1	3,218,196	3,650,065	....	....	....	19	19	23	....	10	218	251	214	71	68	68
Dist. 8: West	258	....	6	34	4	302	322	354	1,528,779	4,445	4,212	+ 5.5	22,799,109	20,439,103	6	....	....	17	23	65	....	7	466	538	522	250	287	387
Dist. 9: North	172	....	12	132	4	320	285	248	793,952	3,497	3,742	— 6.6	9,643,335	10,542,486	....	....	1	31	32	23	....	3	513	539	644	157	146	189
Dist. 10: Panhandle	69	....	15	24	....	108	94	76	491,277	1,249	1,306	— 4.4	5,690,223	5,669,330	....	....	....	13	13	14	1	14	127	156	131	90	83	95
Utah	9	....	5	18	....	32	32	25	178,673	291	395	— 26.3	1,623,988	2,189,909	....	....	1	10	11	5	....	4	75	84	87	30	28	36
Washington	....	....	....	1	....	1	....	1	10,820	4	7	— 42.9	31,928	40,635	....	....	....	1	1	....	....	....	4	4	6	1	1	1
West Virginia	10	....	45	15	....	70	62	73	187,342	783	836	— 6.3	2,009,755	2,239,102	....	....	....	....	....	....	....	....	1	1	6	210	186	219
Wyoming	43	....	10	57	....	110	95	74	553,169	898	711	+ 26.3	4,687,227	3,326,345	3	....	1	42	46	22	1	10	317	350	223	78	85	93
Others	....	....	....	7	....	7	11	9	15,944	47	53	— 11.3	134,732	231,403	....	....	....	6	6	1	....	1	38	40	28	5	6	5
Total United States	1,946	67	374	1,645	43	4,075	3,771	4,041	17,260,546	48,328	48,670	— 0.7	202,528,285	195,083,688	65	3	24	801	893	713	85	281	8,829	9,908	9,799	4,094	4,183	4,445
Total Western Canada	100	....	25	75	....	200	215	238	1,000,000	2,475	2,588	— 4.4	12,364,130	12,949,373	....	....	....	....	....	....	....	....	....	....	....	249	193	243

* Gulf of Mexico wells are included in their respective district total.

Si
re
ga
se
ci
fo
hu
co
es
fo
Th
pl
re
Th
of
wo
BE

--the revolutionary dehydrator that requires no pump or process heater



The San Juan Basin, Big Piney and the provinces of Alberta and Saskatchewan are among the cold weather areas that have served as proving grounds for the Rolo $CaCl_2$ Gas Dehydrator. Under wintery conditions, efficient gas dehydration is all the more essential, but far more difficult to achieve. Yet, the hundreds of Rolo Units in these areas have performed with marked success.

The Rolo Calcium Chloride Gas Dehydrator employs a long-lasting bed of calcium chloride to remove water vapor from gas streams. Top efficiency is obtained by utilizing the brine, in a series of patented jet trays, to pre-dehydrate the gas before it contacts the chemical bed.

Advantages over competitive systems:

SIMPLICITY . . . No pumps, since regeneration is not required. Only moving parts are the level controls.

LESS HAZARDOUS . . . No process heat required, since there is no regeneration.

ATTENDANCE-FREE . . . Absence of pump and regenerative heater allows unattended operation for long periods—especially important in cold areas and offshore.

LOW OPERATIONAL COST . . . Cost per MMCF is low in comparison with other systems.

LOW INITIAL COST . . . Get our prices and compare.

MAXIMUM DEWPOINT DEPRESSION . . . The ability of calcium chloride as a dehydrating agent, especially with utilization of the brine, is unequalled in water vapor removal.

INTEGRAL SCRUBBER . . . Standard on all models; removes free liquids from the incoming stream.

BETHLEHEM STEEL

Contact your nearest Bethlehem representative for information and prices on Rolo products.
In California, Howard Supply Company. In Canada and for export, see below.

ROLO

BETHLEHEM STEEL COMPANY
SUPPLY DIVISION
General Offices: 21 E. Second St., Tulsa, Okla.

ROLO MANUFACTURING COMPANY
P. O. Box 22126, Houston 27, Texas
Canada: Petro-Automation Industries, Ltd., Edmonton, Calgary and Regina
Export: R. S. Stokvis & Sons, New York, N. Y.

**Originated by Fish Engineering Corporation*

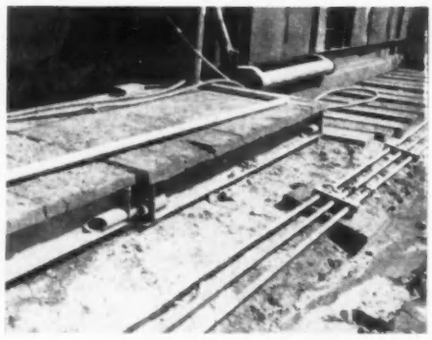
Practical Operating Hints

These How-To-Do-It Ideas Can Save You Money

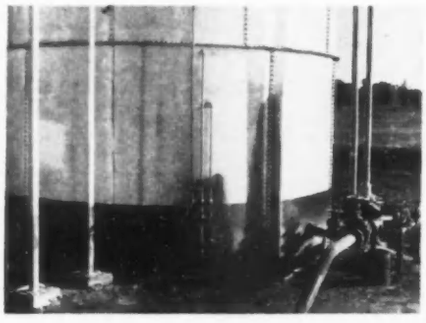
$10 is paid for each illustrated acceptable contribution. Mail to The Editor, WORLD OIL, P. O. Box 2608, Houston 1, Texas

Welded-In Eyes Speed Skid-Base Handling

Safer and faster loading and unloading of mud pump skid bases or mats is possible by using the idea employed by one drilling contractor. Instead of relying on slings looped around the base, short pieces of 2½-inch tubing, with ends cut as illustrated, are welded into the web section of the I-beam members at each end of the unit.



Running a wire line or sling through the two eyes thus provides a means of lifting with a crane or gin pole without possibility of the load slipping out of control should the hoisting line slacken unexpectedly. The small amount of welder's time and materials involved easily can be justified in savings in handling time.



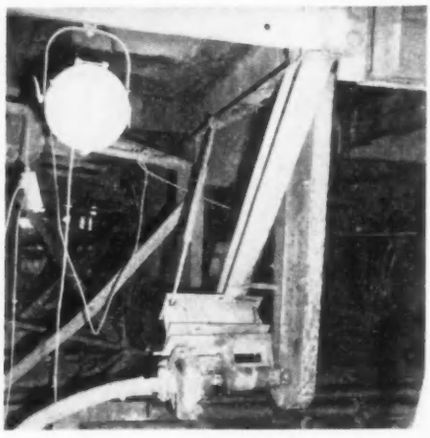
Manifolded Sample Cock Makes Neat Hook-Up

Connecting tank sample cocks to a common low-level discharge make for a neater appearing battery by avoiding leaking oil onto side of the tank.

The three ¼-inch tank taps are equipped with appropriate lengths of ¼-inch pipe and provided with needle valves at the lower end. All three taps are tied into a common discharge with a ¼-inch cross.

Mount Centrifugal Water Pump on Substructure Beam

Here's a way to mount the rig centrifugal water pump with minimum of trouble and expense. The pump, already equipped with its own unitized base, is mounted on a short section of about 10-inch H-beam. A hinge is made at the point where the distant edge of the base joins the H-beam flange, this serving the dual purpose of being the pump mount; also being a means of adjusting belt tension. The H-beam, in turn, is bolted at the desired point on the under side of one of the sub-base diagonals. V-belting, from the drive group above, is brought down through an opening in the floor and is completely housed in an easily-opened sheet metal guard.



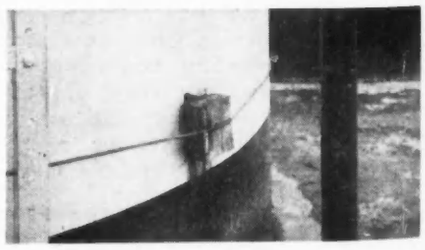
Adjustment of belt tension, and holding it at any point desired, is done merely by taking up or letting out on a heavy adjustment bolt that holds open the hinged mounting sections. Horizontal adjustment for sheave alignment is accomplished by loosening the mounting bolts and sliding the entire unit either way through slots burned in the H-beam flange. Additional stability for the unit is obtained in a turnbuckle that extends between the outboard end of the H-beam base and one of the overhead sub-structure beams.

This type of installation utilizes rig power without cluttering the area adjacent to the drive group; puts the water pump within easy reach by workmen when repairs or servicing are necessary; keeps the unit off the ground where it does not interfere with rig mud, fuel and other utility lines; and is easily unbolted or removed whenever necessary.

Use Scrap Pipe to Mark Location of Buried Valves

A piece of scrap 1-inch pipe driven into the ground next to a buried valve serves as a marker for field personnel or as a caution sign to any unwary passerby.

The marker can be particularly helpful where buried valves or other control equipment is located adjacent to roads where passing vehicles might damage them.



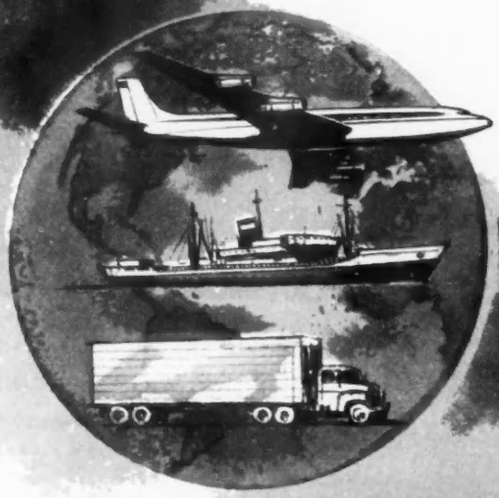
Block, Inner Tube Rubber Prevent Tank Leak

This lease pumper was faced with the problem of stopping a tank leak immediately, and with no lead plugs available, he installed the "stopper" illustrated here. Several pieces of rub-

ADVANCED ENGINEERING

CONSTANT RESEARCH

MODERN MACHINING



WORLD-WIDE DISTRIBUTION

Smith TOOL CO.

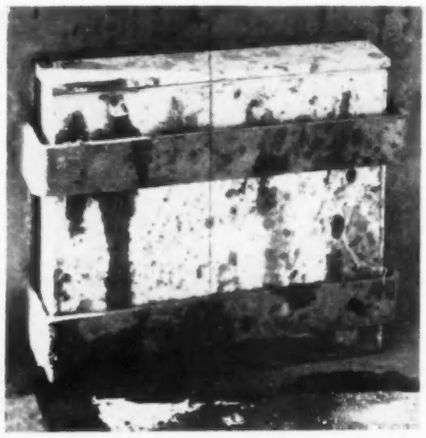
(FORMERLY H C Smith OIL TOOL CO.)

Branches in Principal Oil Centers
Throughout the World

COMPTON, CALIF. • OKLAHOMA CITY
ODESSA • HOUSTON • DALLAS
GREAT BEND • EDMONTON

ber were cut from an old inner tube and placed over the hole in the tank. A block of wood then was placed over the pieces of rubber and a cable placed over the wood.

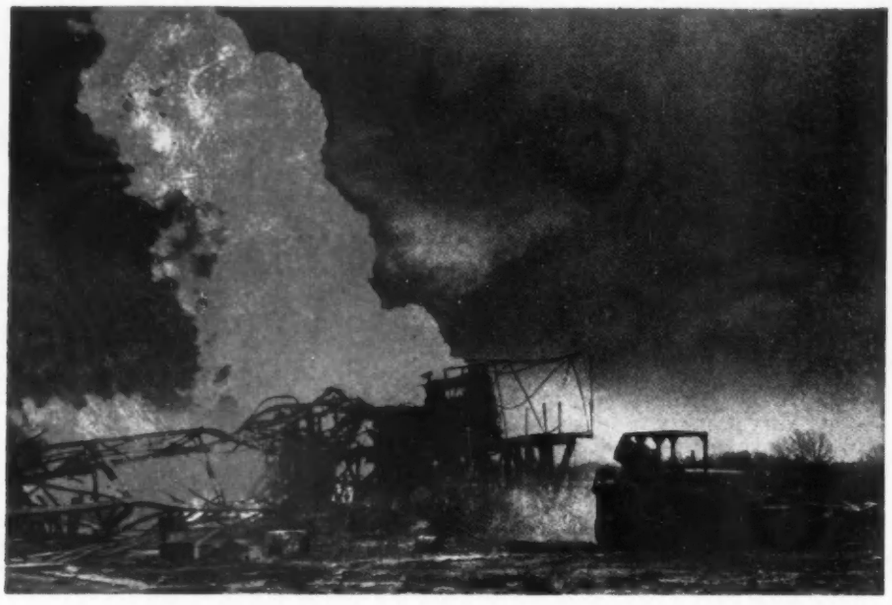
The cable continues completely around the tank. The ends of the cable are connected with a turnbuckle which, when tightened, causes the cable to compress the wood and strips of rubber tightly into the hole in the tank. The technique provides a very useable tank plug which will last indefinitely and is very economical since only scrap material is used.



Build a Weather-Proof Case for Meter Charts

Build a weather-proof case and carrying cage to keep a complete supply of charts with a portable well testing unit at all times.

Use two pieces of strap steel to make the cage for the case. Weld the straps directly to the tank of the testing unit. The case is carried in the cage. Orifice meter, pressure recorder and other charts can be carried and left with the unit when placed in the case.



Install Air Horn On Compressor Safety Valve

Air horns which are used around a rig for several purposes, can be installed on the safety valve of the compressor to warn the crew when the compressor is overpressured.

These air horns also can be used for signalling the crew that they are needed on the derrick floor.

A "Pit-O-Graf" MIGHT HAVE SAVED THIS WELL

A Pit-O-Graf can give adequate warning to prevent a blowout. But, it must be where the driller can see it, can take advantage of it. Here's what users have to say:

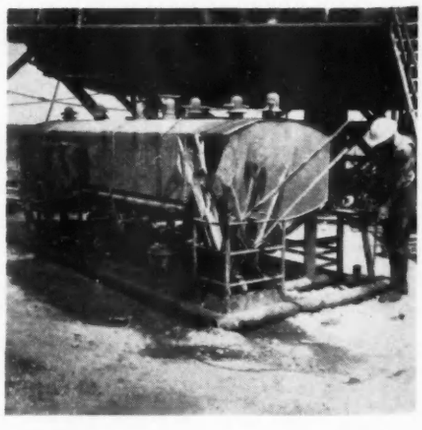
One oil company says — "Although blowout prevention is a matter of concern for the operator, the contractor, and the drilling crews, generally *the driller is the key man.*"

Another company says—"Since a pit level indicator is so important, take these precautions to get the most good out of it: Place the pit level recording instrument at or near *the driller's position on the derrick floor.*"

If the driller's responsibility is not misplaced, then he can recognize the danger signals that precede every blowout. With the Pit-O-Graf record before him, he can intelligently analyze the *rate* of gain or loss of mud as recorded and thereby direct his crew in the orderly control of the situation at hand. In this case the threatened blowout would become *one that does not happen.*

WARREN AUTOMATIC TOOL CO.
3915 THARP STREET • HOUSTON, TEXAS
Phone CApitol 4-2511

Lake Charles	New Iberia	Harvey
HEmlock 6-2265	EMerson 9-9862	FOrest 6-1441

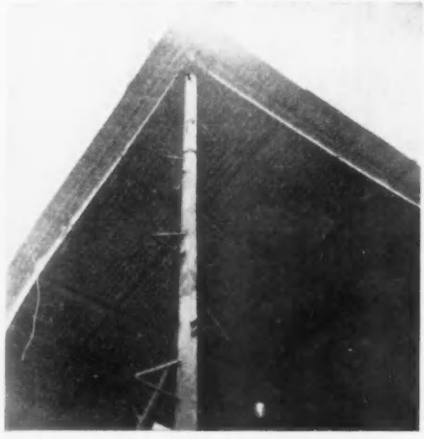


Add a Vise and Tool Rack To Fuel and Lubricant Tanks

For convenience around the rig, attach a vise and a tool rack to the sides of skid-mounted fuel and lubricant tanks. The vise will come in handy

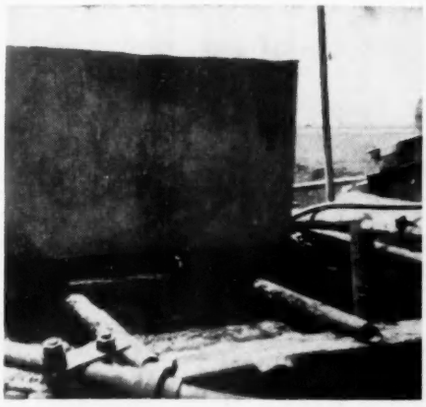
when working on mud pump parts. Shovels, rakes and post hole diggers can be stored in the tool rack.

The tank is divided into seven compartments for each liquid needed on the rig and mounted on skids made of drill pipe. Make the tool rack from 1-inch pipe. The vise stand is made of 2-inch pipe. Build a platform along the left side of the tank to provide a work bench for material which is used in the vise.



Built-In Ladder for Hard-To-Reach Rig Area

A simple ladder built with small diameter rods will make hard-to-reach areas around a rig more accessible. This ladder was built to reach the roof covering of the engine. Each step is made from a length of small diameter rod bent in an A-shape. The steps then are welded to one of the supporting roof posts. Since each of the steps is closed, the ladder is strengthened and safer.



Make Chemical Barrel Support of Old Pipe

Build a convenient support for a chemical barrel by welding two lengths of discarded drill pipe across the mud tanks. When the tank is placed on these supports, chemicals can be added when necessary.

"I've ALWAYS preferred KING GA SWIVELS"

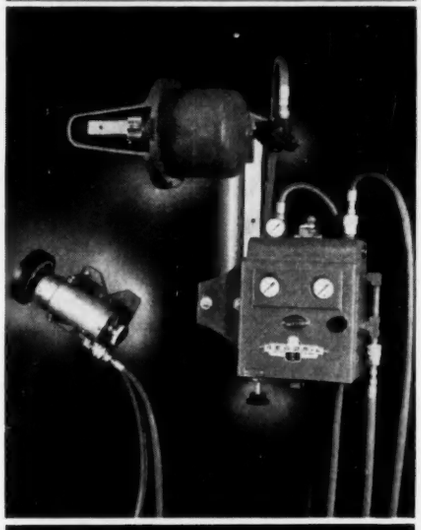
King Swivels 32GA and 53GA have been popular for many years. They have proved to be rugged, dependable and durable, and are in use around the world because they are "preferred". The fact that King Oil Tools is the largest manufacturer of lightweight swivels is supporting evidence of King engineering, service efficiency and complete all-around dependability.

INDUSTRY RECOGNIZES KING GA SWIVELS BY THESE FAMOUS FEATURES:
- ALLOY STEELS assure strength with minimum weight.
- PACKING is V-type, often called chevron type.
- WASHPIPES are seamless alloy tubes, case-hardened and ground.
- GREASE LUBRICATION for the packing.
- MULTIPLE BALL BEARING UNITS provide ample capacity.
- OIL BATH LUBRICATION for the bearings.
- Choice of BAIL OR ELEVATOR SHANK.

FOR FULL INFORMATION ON ALL KING SWIVELS — SEE YOUR NEAREST DISTRIBUTOR — OR WRITE:

KING OIL TOOLS
P. O. BOX 15146 • HOUSTON 20, TEXAS • ORchard 3-3421

The NEW GEODRIL® AUTOMATIC DRILLER



gives you

1. LONGER BIT LIFE
2. FEWER TRIPS
3. STRAIGHTER HOLE

The GEODRIL Automatic Drilling Control was developed, tested and proved in the field by The Geograph Company, manufacturers of the internationally accepted Geograph Mechanical Well Logging Recorder.

The new, automatic GEODRIL control has many outstanding features and offers the drilling contractor dependability, economy and safety.

Service for the GEODRIL Control is provided by the experienced personnel of Geograph Oil Field Services. Their reputation for service is backed by over a fifth-of-a-century of experience in the oil fields.

When you drill your next well, specify the NEW GEODRIL Automatic Driller for maximum drilling efficiency. For additional information, contact your nearby Geograph Oil Field Services office.

GEODRIL® AUTOMATIC DRILLER

GEOLOGRAPH®
OIL FIELD SERVICES
P. O. Box 1276 • Oklahoma City, 1, Okla.

FARGO TOWNSITE UNIT WELL #2. All four wells operated by Mr. Moore are equipped with Bethlehem pumping units, Bethlehem sucker rods, and Bethlehem Beeline bottomhole pumps.

Fifth year for X-2 rods in four Rex R. Moore wells

Bethlehem Rod Package Handles Easily

Bethlehem Sucker Rods come securely bundled in an easy-to-handle unit package containing 80 or 100 rods. Rods rest on grooved spacers which prevent individual rod movement, protect rods against damage. Special wrench can be furnished for opening bundle.

Rex R. Moore operates four wells in the Fargo Townsite Unit Field, Willbarger County, Texas. In November, 1954, he installed strings of Bethlehem X-2 rods in these wells. Three of the strings are made up of $\frac{5}{8}$-in. X-2 rods, 3,950 ft long. One string consists of 3,975 ft of $\frac{3}{4}$-in. X-2's. All four wells produce 41-gravity oil from the Lower Canyon Sand Formation. Production varies from 30 to 55 bpd. The rods have never been pulled, since not a single rod has failed to date.

The Bethlehem X-2 rod is ideal for medium pumping duty in non-corrosive wells, as well as in wells which are effectively inhibited. Made from top-quality carbon-manganese steel, it is carefully normalized to provide uniform mechanical properties.

In addition to the X-2 rod, Bethlehem produces three grades of alloy steel rods, plus a full line of accessories. There's a Bethlehem rod to meet virtually any pumping condition or corrosion problem. For complete information, just get in touch with your nearby Bethlehem distributor.

BETHLEHEM STEEL COMPANY, BETHLEHEM, PA.

Export Distributor: Bethlehem Steel Export Corporation

BETHLEHEM STEEL

BETHLEHEM STEEL

II. Continued from January Issue

PRODUCING EQUIPMENT FOR NATURAL GAS WELLS

This second installment of WORLD OIL's first Production Practices Manual contains 25 pages of technical operating information on:

- The Glycol Dehydration Unit
- The Short Cycle Hydrocarbon Recovery Unit
- The Ammonia Absorption Refrigeration Unit as used in low temperature separation.

Included are details of countercurrent and concurrent glycol absorbers; short cycle unit regeneration gas systems; and how refrigeration equipment is used on rich gas streams.

NEXT MONTH

The third and final part of the Production Practices Manual on Producing Equipment for Natural Gas Wells will appear in the March issue of WORLD OIL. It will cover: Three Phase Separation, Indirect Flow Line Heaters and Pneumatic Control In the Field.

5. THE GLYCOL DEHYDRATOR

By George J. Mapes, Product Application Specialist Parkersburg Rig and Reel Company, Houston

GLYCOL TYPE well stream dehydration units are used for many gas drying applications. Although a variety of glycol dehydrators are available commercially, this type unit usually is selected for a particular job for one or more of the following reasons:

- Installation cost is relatively low.
- Operating costs are comparable with other types of dehydrators.
- Pressure drop through the unit is low (5-10 psi)
- High gas inlet temperatures (up to 140° F) can be handled easily.
- Low pressure gas streams can be processed with ease.
- Economic means of achieving moderate dewpoint depressions when only moderate depressions are required. A typical glycol unit installation is shown in Figure 1.

The glycol dehydrator has no facility for recovering liquid hydrocarbons and can show no payout in this respect. However, the units frequently are used in lieu of dry desiccant type dehydrators and low temperature separation units.

For example, a low pressure gas stream automatically eliminates application of low temperature separation since the Joule-Thompson effect depends upon an available 1,000-2,000 psi pressure drop above sales line pressure to achieve the low separation temperatures required. Also, short life expectancy of a particular high pressure reservoir

may not justify temporary installation of a low temperature unit.

The high temperature of the gas stream at the inlet of the unit may make the large size dry desiccant dehydrator required impractical for the small gas volume to be dehydrated. Gas inlet temperatures as high as 140° F can be handled easily with glycol dehydrators. Also, A minimum water dewpoint depression requirement may not justify the more expensive dry desiccant equipment which is well known for its low water dewpoint result.

Although glycol and dry desiccant dehydrators both are adaptable to low pressure streams (300-2,000 psig), a re-

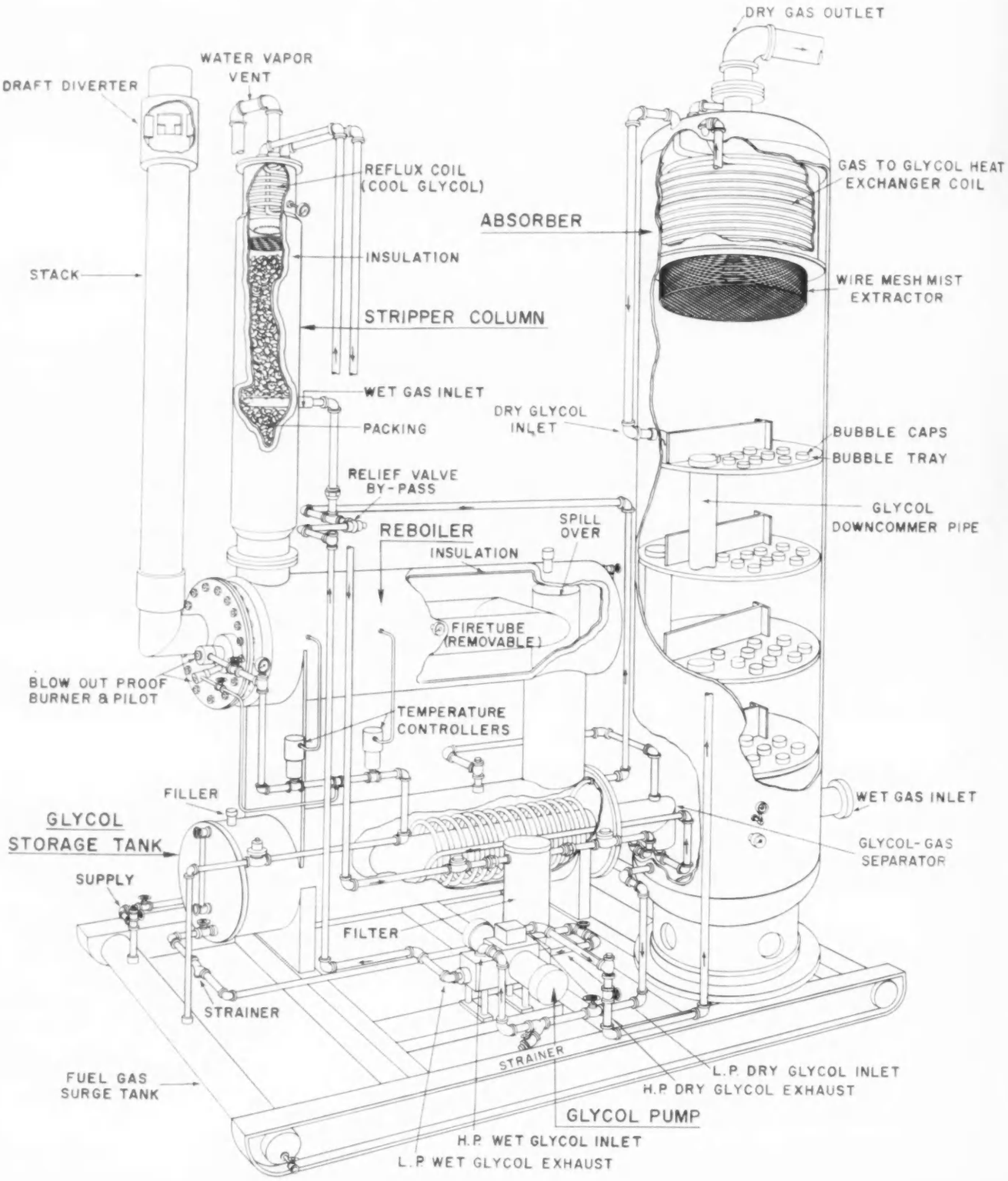
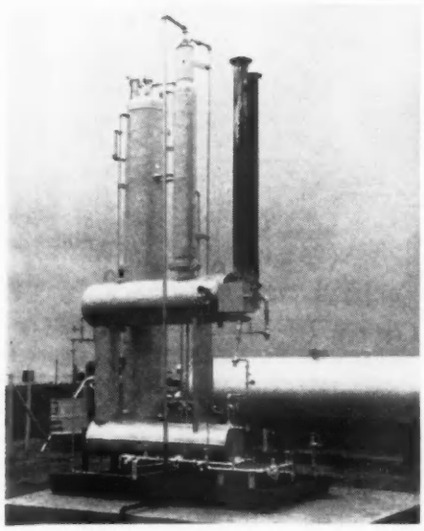
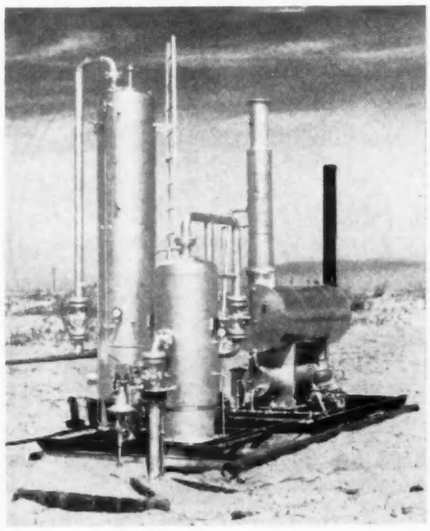


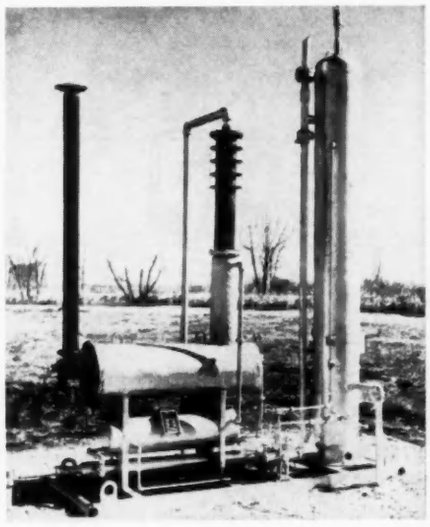
FIGURE 1—Typical glycol dehydration unit installation.



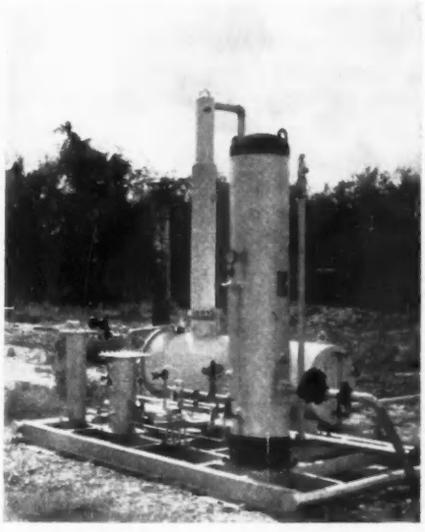
A



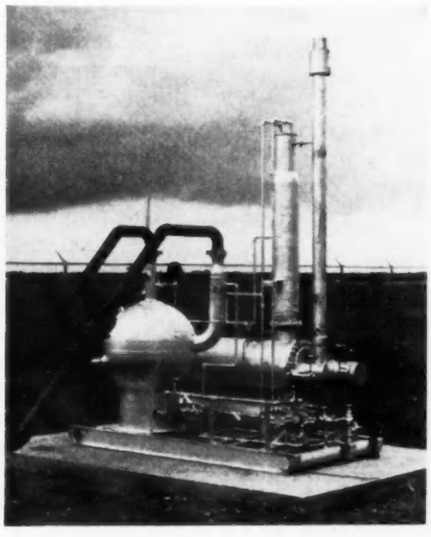
B



C



D



E

Glycol dehydration units are manufactured in various physical shapes and sizes as indicated in the photographs. Photos A—D show units which utilize countercurrent flow of gas to glycol in the absorbers. The dehydrator in Photo E utilizers concurrent flow of gas and glycol.

striction on pressure drop through the unit may indicate use of the glycol method. The expected pressure drop through a glycol unit is from 5-10 psi maximum as compared to 15-30 psi expected in dry desiccant units. This is a critical factor when low pressure gas must be compressed to sales line pressure, or when well-head pressure exceeds sales line pressure by a small margin.

Short cycle dry desiccant dehydrators show an excellent payout when installed on a stream rich in heavy hydrocarbons, since they not only achieve a very low water dewpoint but also recover essentially all of these heavy ends. This results in a low hydrocarbon dewpoint. However, this may not be a desired feature because:

1. The gas stream may be too "lean" in heavy ends to show justifiable payout.

2. The gas stream may be destined for a conventional gasoline plant.

3. Lease arrangement may not make hydrocarbon recovery economically practical at the necessary dehydration point.

4. The well may be located in a remote area where there is no market for the liquid hydrocarbons. Under these conditions, the glycol type dehydrator might be favored since it requires a lower investment.

The cost of operating glycol units is in line with that of other types of dehydrators since improved refluxing and glycol reclamation methods make glycol losses negligible (in the range of one-tenth gallon per MMscf of gas processed or less).

EQUIPMENT

Countercurrent flow absorber. The countercurrent flow process utilizes a vertical cylindrical ASME Code constructed pressure vessel, usually with internal bubble trays in large units and packing (ceramic, plastic, wire mesh) in small diameter absorbers (Figure 1).

Packing usually is used in smaller 12-inch and 16-inch diameter absorbers, and sometimes in larger absorbers. In a small diameter absorber, packing is as effective as bubble traps which are not as adaptable to smaller diameters. In larger diameter absorbers, packing is more conducive to gas channeling.

The ceramics are designed in semi-circular rims or saddle shapes in order that packing and settling allows them to interlock, maintaining sufficient gas flow area between them to prevent excessive pressure drop. A steel mesh has been used for dispersion media in some absorbers with equal success. Here, corrosion can be a problem unless stainless steel mesh is used.

Glycol enters the top of the absorber and flows downward from tray to tray or over the packing, counter to

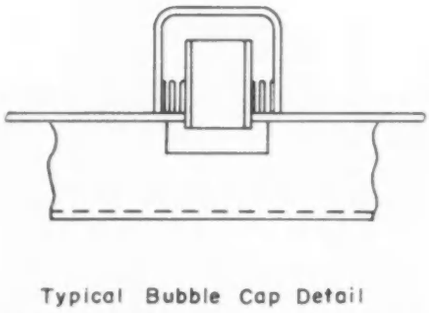


FIGURE 2—Bubble cap used in countercurrent flow absorber.

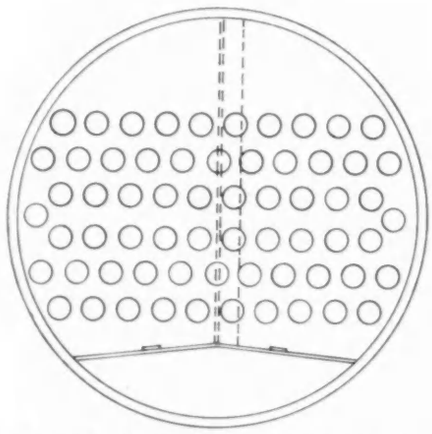


FIGURE 3—Bubble tray layout for countercurrent flow absorber.

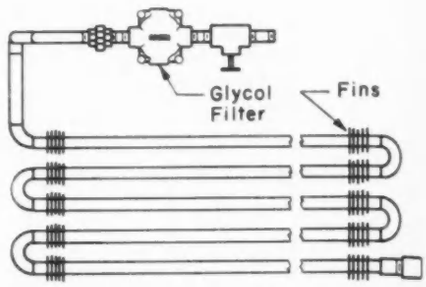


FIGURE 4—Finned tube atmospheric type heat exchanger.

the flow of wet gas which enters the bottom of the absorber and flows upward. Water dewpoint of the gas leaving the absorber cannot be lower than the equilibrium value for conditions of temperature and glycol concentration at the top tray or packing.

Triethylene glycol usually is recommended for use with the countercurrent flow type absorber for dewpoint depression of 65° F at reboiler temperatures of from 365-375° F. With special equipment, dewpoint depressions up to 105° F and greater are guaranteed with triethylene glycol under similar operating conditions.

In some cases, tetraethylene glycol has been recommended for gas dehydration. Reconcentration to 99 percent glycol by weight is obtainable below the decomposition temperature of the tetraethylene glycol. Reboiler temperatures in the range of 450° F are required.

Tetraethylene glycol is less hygroscopic (will hold less water) than triethylene and therefore must be circulated at a higher rate. Under conditions of equal concentration, triethylene glycol will achieve a greater dewpoint depression than tetraethylene glycol.

The bubble tray. Contact efficiency of the glycol with the gas is controlled by proper bubble tray design wherein the slot velocity of the gas through the bubble caps (Figure 2) produces small bubbles which allow maximum mass transfer as they form.

The layout of the bubble caps (Figure 3) is important in preventing glycol channeling along the walls of the absorber. If the caps are placed too close together, glycol entrainment in the gas will increase and dehydration efficiency will decrease. Optimum dehydration efficiency is reached with a liquid depth of 1½-inch in the tray.

The number of contact opportunities, of course, depends upon the number of bubble trays used in the absorber. Adding extra trays permits the glycol in the top tray to remain drier, which results in a greater dewpoint depression. Increasing the circulation rate of the glycol presents a drier or more highly concentrated glycol for each contact with the gas. This also results in a greater dewpoint depression.

Good design also provides adequate spacing of trays so that the greatest amount of entrained glycol will drop out of the gas and not be carried upward to the next tray and finally to the mist extractor.

The mist extractor. A mesh type mist extractor (Figure 1) properly placed can remove essentially all entrained

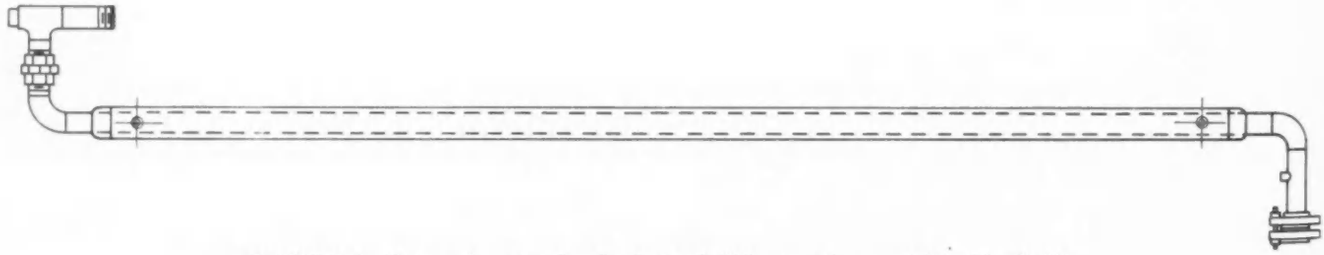


FIGURE 5—External gas to glycol tube-in-shell heat exchanger (glycol in Shell).

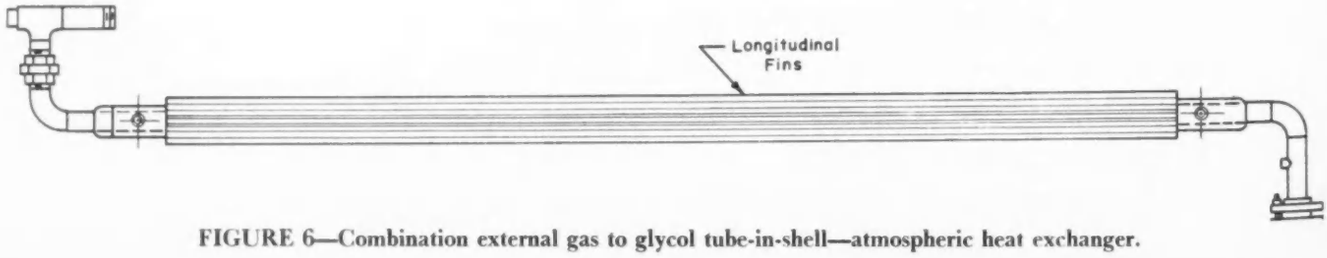


FIGURE 6—Combination external gas to glycol tube-in-shell—atmospheric heat exchanger.

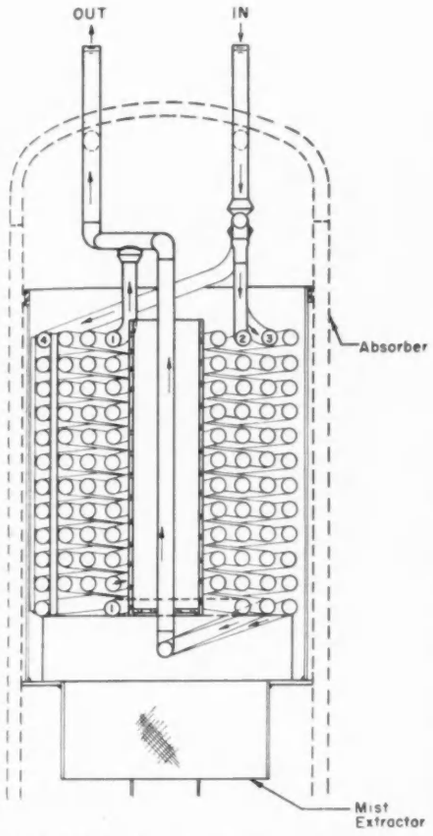


FIGURE 7—Internal gas to glycol heat exchanger.

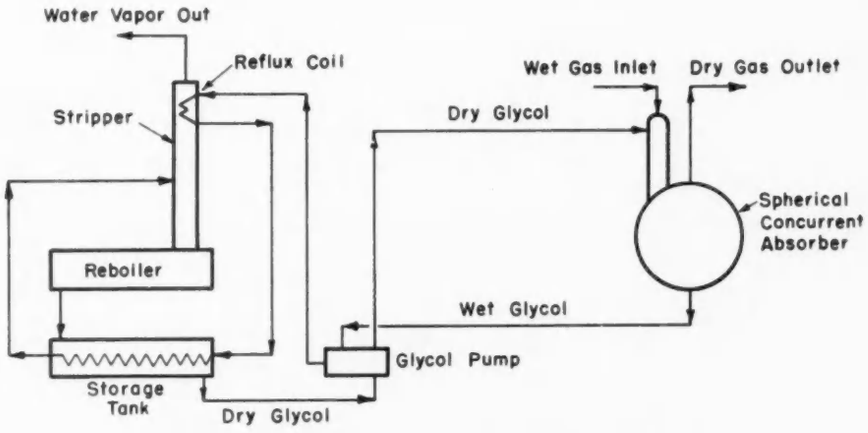


FIGURE 8—Flow diagram for concurrent type absorber.

glycol from the exeunt gas stream, provided maximum design velocities are not exceeded. The stainless steel type mesh is recommended for corrosion resistance. Adequate spacing between the top tray and the mist extractor must be provided to prevent excess liquid loading in the mist extractor and resultant loss of glycol even before normal design capacity is reached.

The heat exchanger. One of the following types of heat exchangers normally is used in connection with the absorber as the final step in cooling the regenerated glycol to absorber contact temperatures:

1. A finned tube atmospheric type (Figure 4).
2. An external gas to glycol tube in shell type in which the exeunt sales gas is used for cooling (Figure 5).
3. A combination external gas-to-glycol—atmospheric type (Figure 6).
4. An internal coil, gas-to-glycol type, wound into the upper section of the absorber and also cooled by the departing gas (Figures 1, 7).

Concurrent flow absorber. Where the countercurrent flow design restricts gas velocities through the absorber to prevent diffusion or entrainment of glycol in the gas, the concurrent flow design encourages thorough mixing of glycol with the gas (Figure 8). The glycol and gas flow in the same direction through a very small cylinder containing a dispersion packing. The cylinder may be no more than a few inches in diameter and one or two feet in length. A cylinder equal to approximately one-fifth the diameter of the equivalent countercurrent absorber is sufficient.

Such complete mixing and absolute contact of glycol and gas is achieved that an extremely "dry" glycol is not required for effective dehydration. (No more than 98 percent glycol and 2 percent water by weight.)

Separation and demisting to remove the glycol from the dry gas must follow. The complete absorption and separation facilities can be contained in a very small chamber. Spherical type vessels ranging from 12-inch to 30-inch in diameter are capable of handling up to 10.0 MMscf/d or more, dependent on gas pressure.

Less expensive diethylene glycol is recommended for use in the concurrent flow absorber, since a lower percentage glycol reconcentration is permissible and reboiler temperatures of about 310°-340° F are possible. At concentrations of 98 percent and lower, diethylene glycol provides better depressions than equal concentrations of triethylene glycol. A dewpoint depression of 60° F normally is guaranteed. Also, hydrate protection, as a result of small glycol carryover, over a 100° F range is not uncommon. Concurrent flow allows effective dehydration from gas inlet temperatures up to about 120° F but does not appear to be as effective in dehydrating to an extremely low water dewpoint.

Glycol losses through the concurrent absorber are within a guaranteed maximum of one tenth of a gallon per million standard cubic feet of gas dehydrated.

Dehydrators utilizing the concurrent absorber are much smaller, weigh less and are less expensive than those using countercurrent flow absorbers which are designed for the same gas handling capacities.

Glycol pumps. One of three types of pumps generally are used to circulate glycol between the regenerator, which operates at atmospheric pressure, and the high pressure absorber:

1. High-pressure gas operated (Figure 9).
2. High-pressure liquid operated (Figure 10).
3. Electrically operated (Figure 11).

Of these, the high pressure liquid operated is the newest and merits some discussion at this time.

Energy for the double acting pump is supplied by high-pressure, wet glycol taken from the sump in the bottom of the absorber, thus recirculating the low pressure, dry glycol from the regenerator to the absorber. A glycol dumping mechanism (liquid level controller and dump valve or trap) is not needed on the absorber, since the glycol liquid level is maintained in the absorber by the demand placed upon it by the pump. The pump uses about 20 percent and 80 percent liquid by volume.

The wet exhaust glycol from the pump flows to the

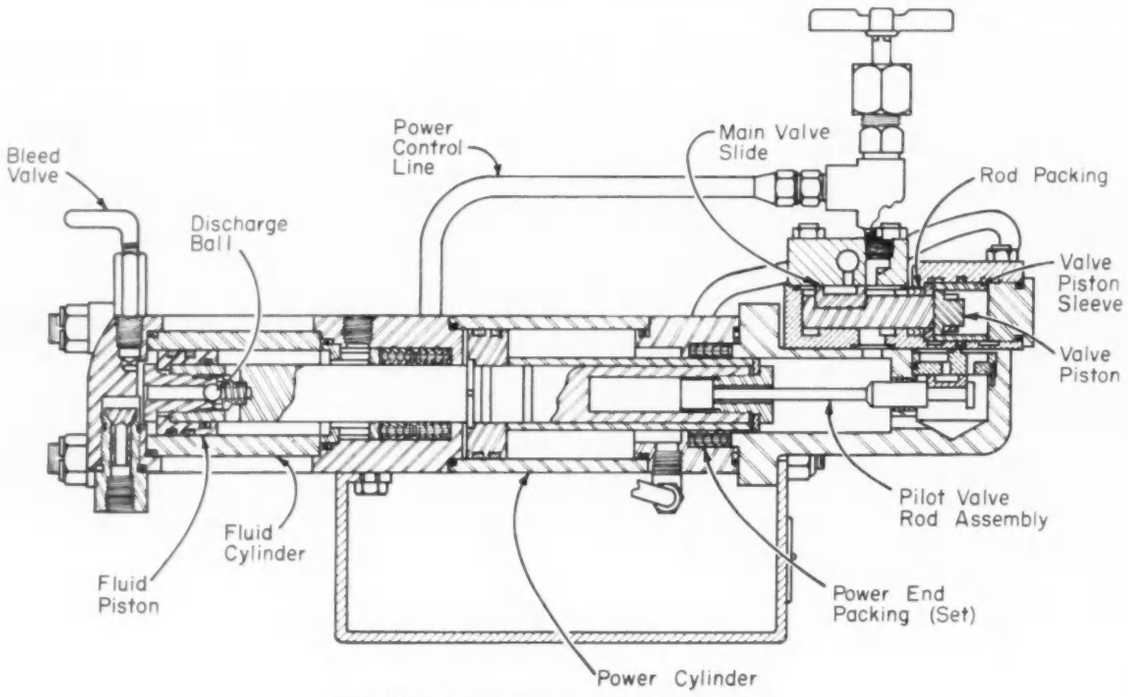


FIGURE 9—Gas operated glycol pump.

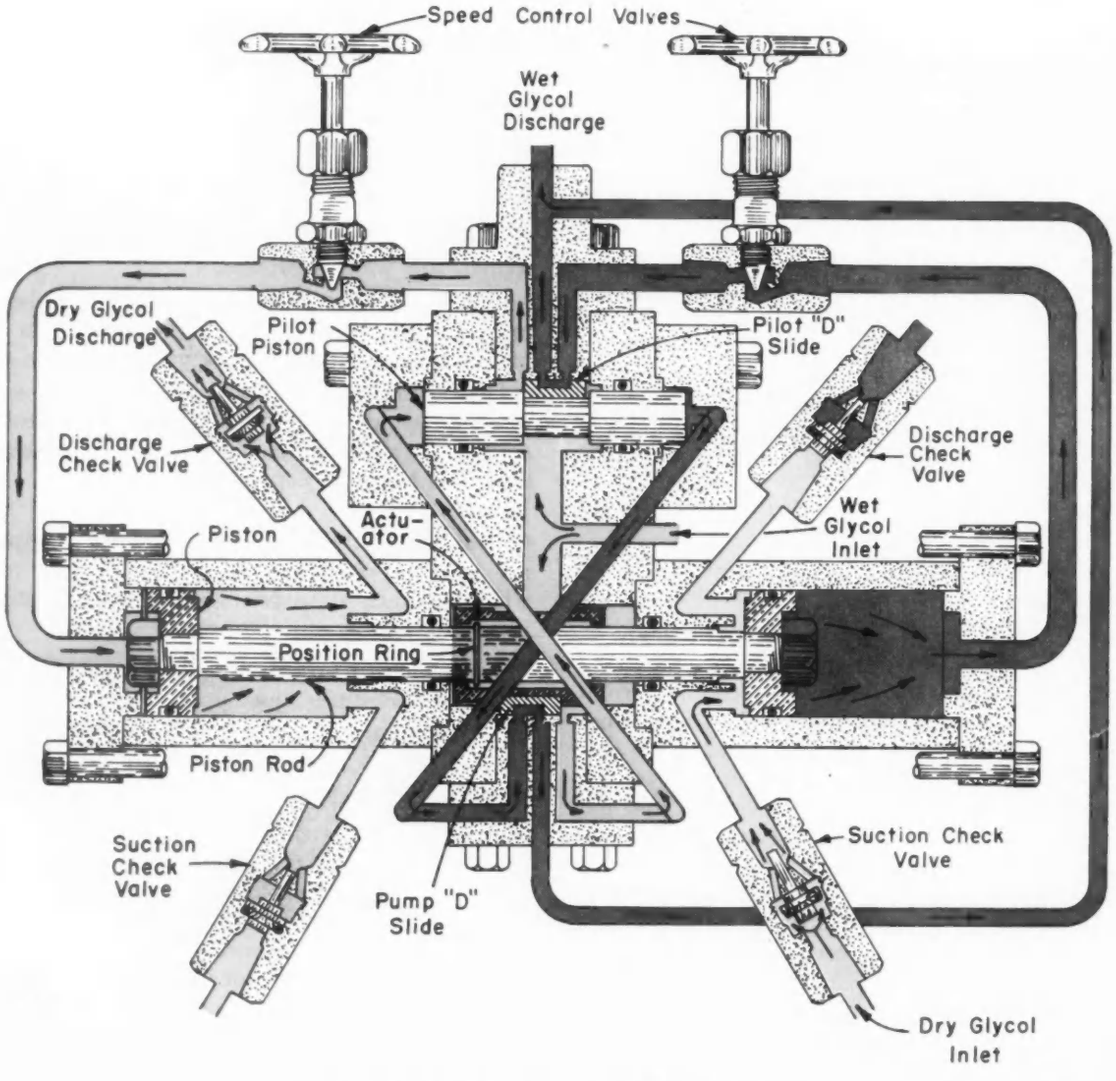


FIGURE 10—Liquid operated glycol pump.

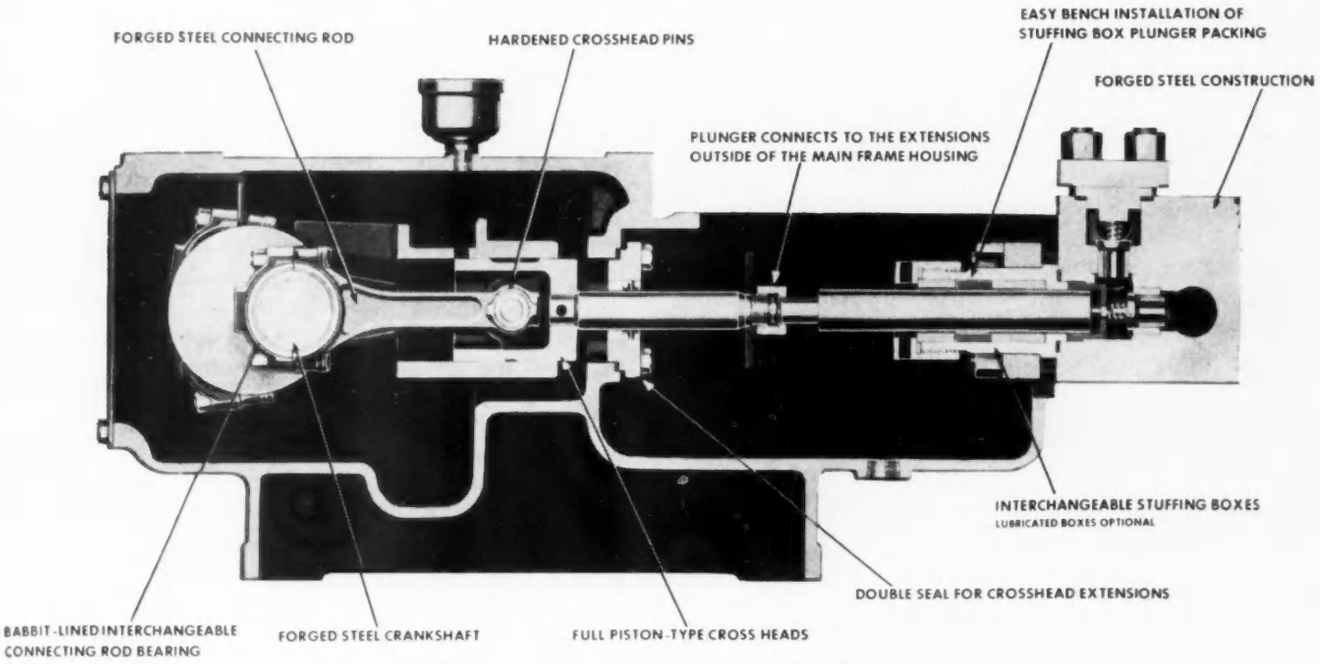

FORGED STEEL CONNECTING ROD
HARDENED CROSSHEAD PINS
EASY BENCH INSTALLATION OF STUFFING BOX PLUNGER PACKING
FORGED STEEL CONSTRUCTION
PLUNGER CONNECTS TO THE EXTENSIONS OUTSIDE OF THE MAIN FRAME HOUSING
INTERCHANGEABLE STUFFING BOXES
LUBRICATED BOXES OPTIONAL
DOUBLE SEAL FOR CROSSHEAD EXTENSIONS
BABBIT-LINED INTERCHANGEABLE CONNECTING ROD BEARING
FORGED STEEL CRANKSHAFT
FULL PISTON-TYPE CROSS HEADS

FIGURE 11—Electrically operated glycol pump.

reboiler to be regenerated. Here the water is boiled off. The gas in the wet glycol is released through the stripper exhaust along with water vapor. When *extremely* high glycol circulation rates are employed the resultant excess pump gas, when released to the stripper column, can cause excessive glycol losses by upsetting refluxing equilibrium. This is especially true at the higher operating pressures where the volume of solution gas is the greatest.

Under normal operating conditions the liquid operated pump has proved to be dependable. Practically all conditions can be successfully handled if provided for in the design of the dehydrator.

GLYCOL REGENERATION SYSTEMS

There are basically three types of regeneration systems used in glycol dehydrators: (a) the open atmospheric type, (b) the closed atmospheric "plus" type and (c) the vacuum type.

The open atmospheric type operates at atmospheric pressure, "breathing" with changes in pressure during intermittent firing. Air which is often induced into this system encourages discoloration of the glycol and accelerates corrosion of the vessels.

The closed atmospheric "plus" type operates a few ounces above atmospheric pressure allowing for possible "exhaling" only through a safety valve if excess pressure builds up. Glycol discoloration and corrosion are negligible in this system as air is excluded entirely.

In the vacuum type regenerator, water is "boiled off" the glycol at pressures well below atmospheric pressure. Since the solution boiling point is greatly lowered under negative pressures, extremely "dry" glycol can be produced with the reboiler operating well below the decomposition temperature of the glycol. The vacuum system requires expensive equipment which normally excludes its application to oil field units.

Reboiler. The reboiler (Figure 1) is usually a horizontal cylinder which receives the wet glycol from the absorber. An immersed firetube transmits heat to the regenerating glycol. The heating process is thermostatically controlled and is fully automatic. If the firetube is subjected to temperatures in the range of glycol decomposition, firetube coating is encouraged, thermal efficiency is reduced and firetube failure will eventually result.

The stripper or refluxing column. Water vapor and light hydrocarbons, "boiled off" the glycol, contain some entrained glycol vapor. This vapor combination is refluxed in the stripper column to reclaim the glycol.

One type stripper is finned (Figure 12) and depends upon changing atmospheric conditions for cooling. Insufficient summertime cooling can result in poor condensation and refluxing, leading to additional loss of glycol. Extreme winter conditions can cause excessive condensation resulting in reboiler overloading. The finned stripper can be used for dewpoint depressions up to 75° F and beyond.

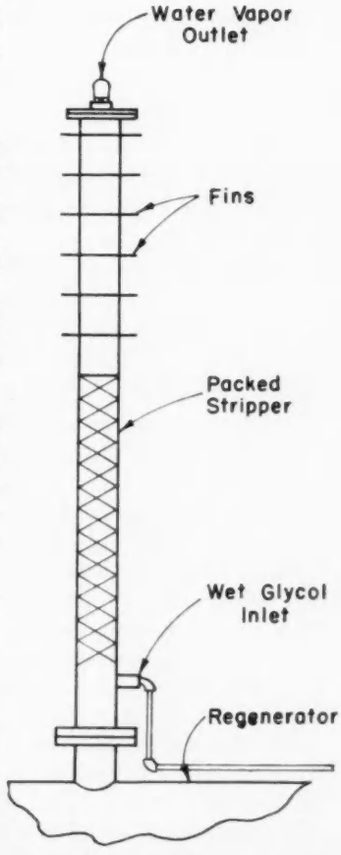


FIGURE 12—Finned atmospheric type stripper.

Another type stripper is insulated and utilizes an internal refluxing coil circulating cool glycol returning from the absorber (Figure 1). This type stripper maintains uniform year round refluxing, and results in the lowest glycol loss and the most economical reboiler operation.

The storage tank. Since most units now operate with a negligible loss of glycol, smaller storage tanks can be used. A large storage capacity to maintain a sufficient glycol supply between make-up periods is no longer needed and it is less expensive for the operator to maintain a smaller glycol charge.

After being regenerated in the reboiler, the glycol begins cooling in the storage tank. A submerged preheat coil in the storage tank is advantageous in transferring heat to the cool, wet glycol before it enters the reboiler (Figure 1). This feature reduces reboiler fuel consumption costs and permits easier reboiler operation.

DEFINITIONS

Water dewpoint. That combination of temperature and pressure of a gas stream at which the gas is saturated with vapor and condensation to the liquid phase begins.

Dewpoint depression. The removal of water vapor from a gas stream at constant temperature and pressure such that water vapor saturation is not again possible unless, with pressure held constant, the temperature is lowered to a given point.

Gas hydrates. Gas hydrates can form at high pressures when the temperature is well above the freezing point of water provided "liquid" water is present and *able* to join in the formation of the hydrate crystal. Water can be present in liquid form but unable to join in the formation of the hydrate crystal if an "antifreeze" agent such as glycol is present in very small amounts.

Thus, the dewpoint and hydrate point do not always coincide. When the dewpoint has been depressed to a point of relatively low water content in the gas, traces of glycol in the stream can depress the hydrate point far below the water dewpoint.

WIDE RANGE DEWPOINT AND HYDRATE PROTECTION

The large amounts of water that a saturated gas contains at temperatures up to 140° F can be removed, producing "dry" sales gas with dewpoint depressions up to 105° F.

The problem is not dehydrating from 140° F, but obtaining the high reconcentration of glycol needed to produce sales gas with a water content of 7 lbs. or less per MMscf of gas processed. Increasing the number of trays in the absorber or increasing the glycol circulation rate, or both, will result in a greater dewpoint depression than normal. The dewpoint depression limit is reached, however, when the glycol in the top tray is able to retain essentially the same concentration as the regenerated glycol at the inlet to the absorber. There is no further gain in dewpoint depression until it is possible to regenerate the glycol to a higher level of concentration.

By reversing the above approach, it can be seen that an absorber with fewer trays and a smaller regenerator utilizing a lower circulation rate can be used when a more highly reconcentrated glycol is provided.

Reboiling the glycol at relatively high temperatures results in higher reconcentration, but usually at the expense of slightly higher glycol losses, possible decomposition, coking the firetube and possibly other mechanical trouble.

Vacuum reboiling, as stated previously, is effective but requires expensive equipment.

Gas stripping is accomplished by passing dry gas over the reconcentrated glycol. In reaching equilibrium, the stripping gas absorbs the remaining water from the glycol to bring the glycol to a reconcentrated level ranging up to 99.7 percent by weight. This concentration provides not only the wide dewpoint depression spread, but also provides extremely dry gas (2 lbs. of water per MMscf of gas and lower) and dewpoints as low as —20° F on medium to low pressure streams are guaranteed.

Adequate stripping gas can be obtained by separating gas from the glycol which is exhausted from the liquid operated pump or by using the exhaust from the gas operated pump. The stripping process also may provide additional glycol cooling and strip heavy hydrocarbons from the glycol.

SPECIAL FEATURES

Very often, a little extra spent on special features, will pay out quickly through fuel and glycol savings and reduced attendance and maintenance costs.

An *inlet scrubber* is practically mandatory to reduce liquid slugging and hydrocarbon contamination of glycol. This reduced liquid load on the regenerator also results in fuel saving. A *flash arrestor* on the pilot and main burner is a safety feature which merits more attention than it has received in the past. A *standby glycol pump*, manifolded for quick switching, can prevent costly shutdown of equipment if pump repairs are necessary.

The *gas stripping feature* can be used very economically to produce highly reconcentrated glycol for the following purposes:

1. To dehydrate from high gas inlet temperatures
2. To achieve a wider range of guaranteed dewpoint depressions
3. To reach an extremely low water dewpoint.
4. To reduce glycol circulation rates, thus permitting the purchase of regenerators as much as 40 percent smaller than otherwise required.

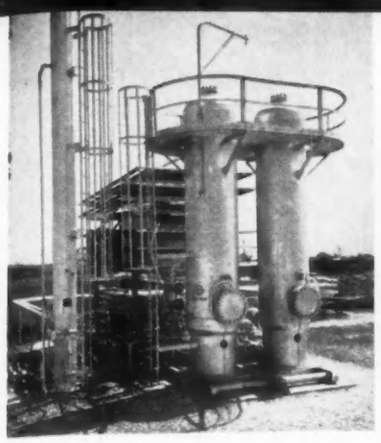
Gas stripping also can be used to permit the reboiler to operate at lower temperatures since high glycol reconcentration can be achieved by this method rather than by boiling at high temperatures. This reduces glycol losses to some degree.

Access manways and intertray manways are convenient in large diameter absorbers to permit internal repairs and vessel cleanout.

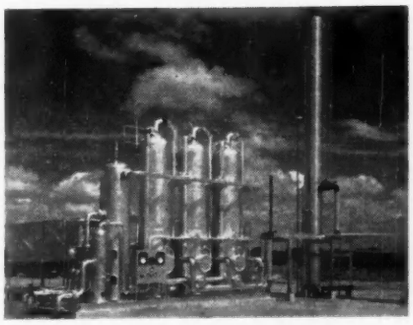
From the preceding information, it is apparent that a dehydrator should be "tailored" to fit any particular gas stream. Equipment manufacturers can recommend the type unit which will be the most efficient from the process standpoint and the most economical from the standpoint of installation and operation.

ACKNOWLEDGMENT

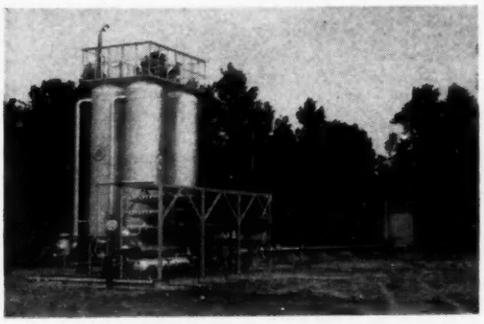
The author acknowledges the aid of Mr. Willi Stahl in editing this article.



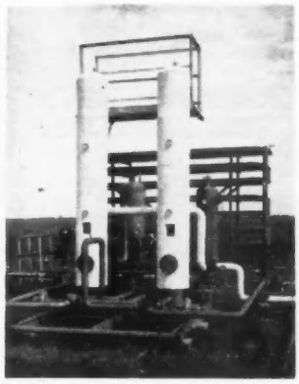
Two tower short cycle hydrocarbon recovery unit with stabilizer.



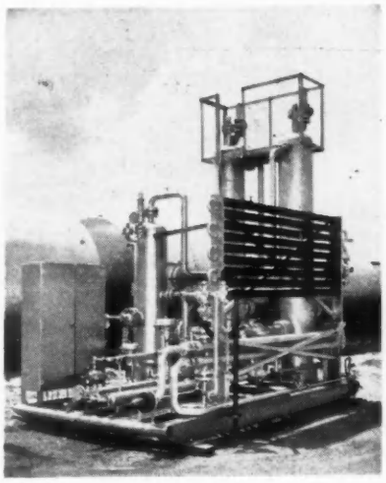
Three tower short cycle unit with forced draft air cooler and stabilizer.



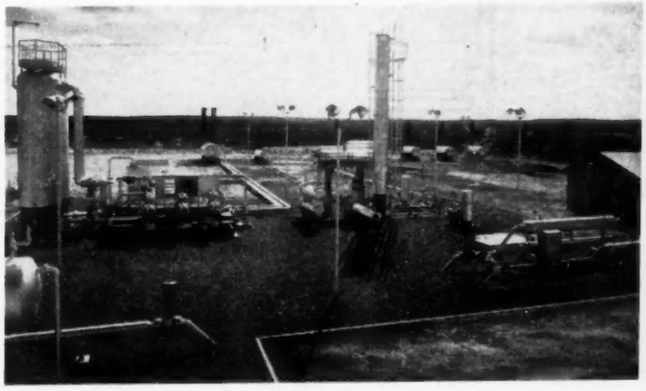
Four tower short cycle unit for LPG recovery.



Twin tower short cycle unit with external adsorber vessel insulation.



Two tower short cycle unit.



Typical centralized installation of short cycle adsorption unit.

6. THE SHORT CYCLE HYDROCARBON RECOVERY UNIT

By R. W. Scott,
Engineering Editor, World Oil

DEVELOPMENT of the short cycle dry desiccant dehydration-hydrocarbon recovery unit for small, lean gas streams has been a significant contribution to the natural gas industry. Many gas producers now are using these units to dehydrate field gas streams and to recover heavy hydrocarbons which previously were "lost" into the sales gas line. Not only does a short cycle unit provide adequate sales gas dehydration, but also additional liquid hydrocarbon recovery will pay out the cost of the equipment relatively soon. Once the capital investment has been regained, revenue from liquid recovery represents income which normally would not have been realized.

Chief advantages of the method are:

1. The unit provides dehydrated sales gas.
2. Hydrocarbon liquid recovery will pay out the cost of the unit.
3. Units are automatic and suitable for unattended operation.
4. Controls are standard oil field equipment familiar to most pumpers and field men.

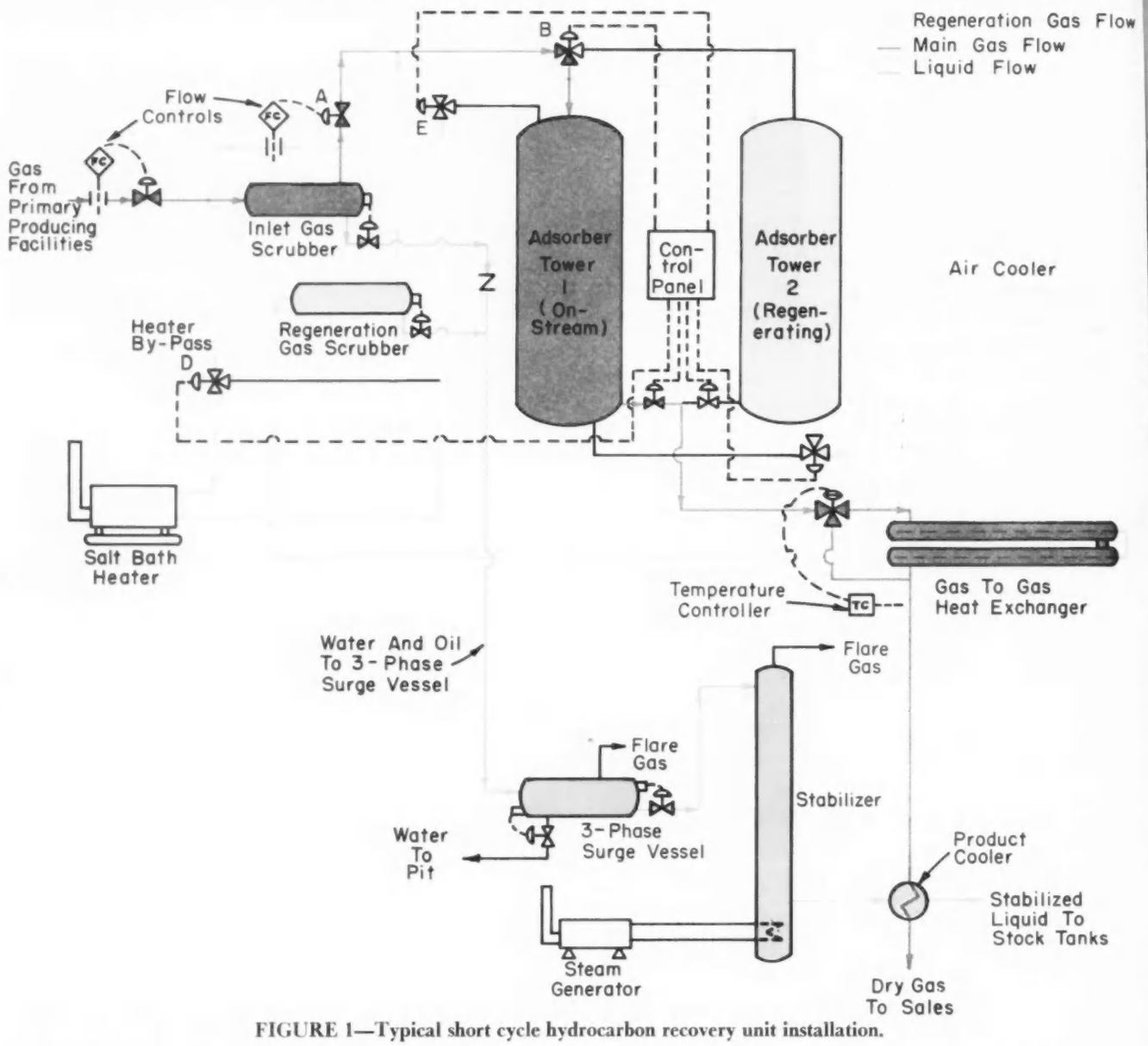


FIGURE 1—Typical short cycle hydrocarbon recovery unit installation.

5. No water or outside power source is required. However, if an operator prefers, an electrically powered gas blower can be used on units which have a closed regeneration gas system. Also, fan type air coolers or water coolers may be used.
6. Units are compact, skid mounted and easily installed.
7. Lean gas streams can be produced economically for hydrocarbon recovery.
8. The unit can be used in conjunction with stage separators or a field stabilizer.

Although the unit has these operating advantages, it also has some disadvantages as does any piece of field producing equipment. Some disadvantages are:

1. Desiccant can be poisoned by compressor lube oil, hydrogen sulfide in the presence of exygen, some well treatment chemicals, ammonia and glycol. Slugs of free liquid may shatter desiccant particles.
2. Unit will not adjust automatically to widely fluctuating flow rates.
3. The short cycle unit requires a relatively high initial investment. A thorough study of the various processes should be made before selecting any one type unit for a particular job.
4. Unit cannot be used economically on lower pressure systems (about 250 psi and below) since condensation is reduced in this vapor pressure range and because adsorber vessels would have to be very large due to limiting gas velocity through the desiccant bed.
5. The raw hydrocarbon product is discharged from units in surges, sometimes making field stabilization difficult. However, proper application of equipment can reduce this to a minor problem.
6. Desiccant capacity determines future utility since basic unit sizing is on the basis of liquid content. That is, the unit used on one installation may not be readily adaptable to another installation.

When the short cycle unit is applied to lean field gas streams which meet operating requirements of the system, advantages of the method outweigh disadvantages. Producers no longer need to deliver heavy hydrocarbons to

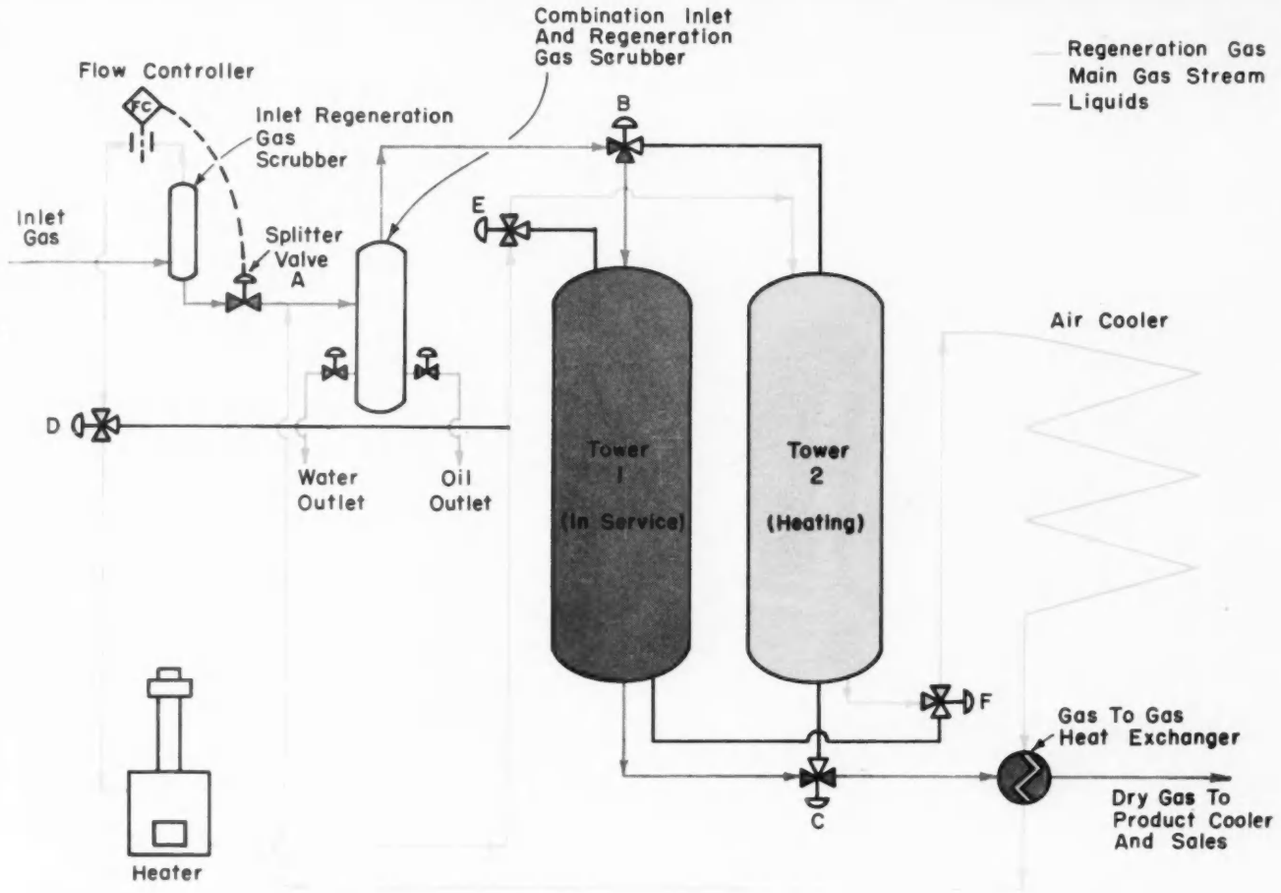


FIGURE 2—Short cycle unit with open regeneration gas system.

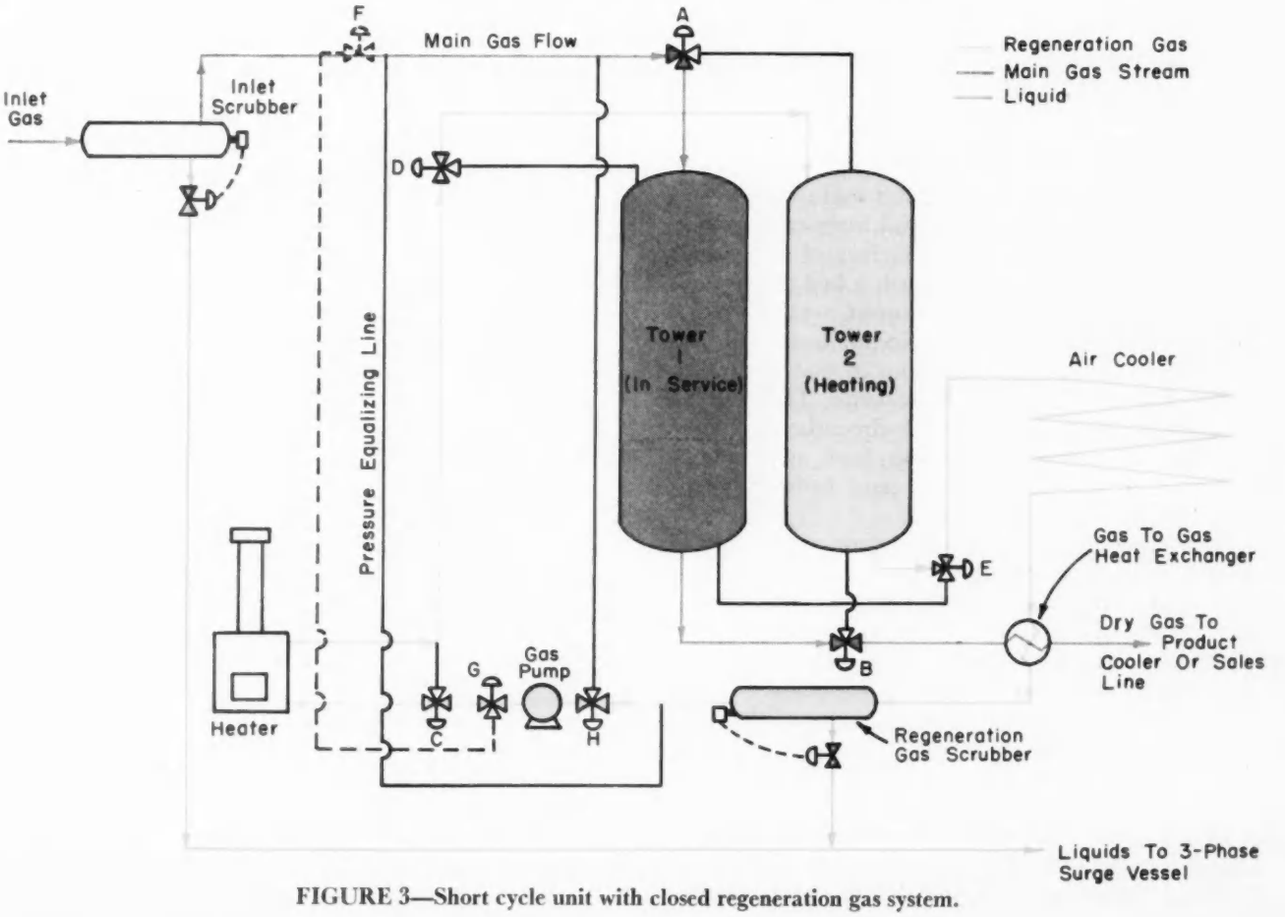


FIGURE 3—Short cycle unit with closed regeneration gas system.

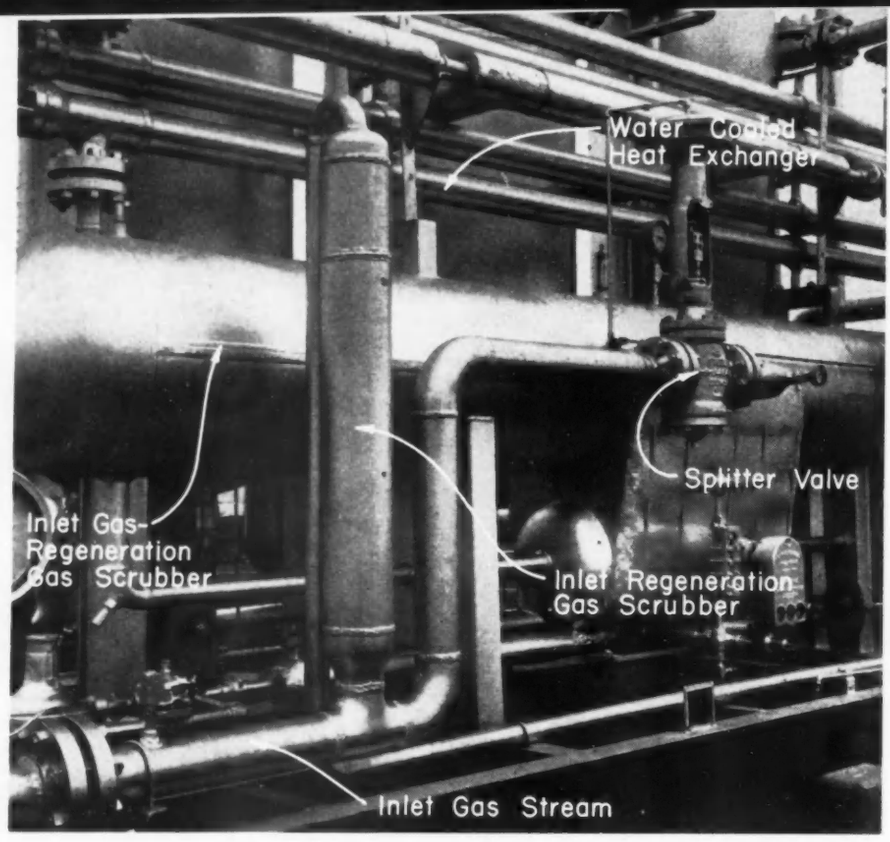


FIGURE 4—Equipment used on short cycle unit with open regenration gas system.

a gas pipe line for a price which is approximately 1/20 of their value if recovered as a stock tank product.[1]

Although long cycle adsorption units have been used widely for several years to dehydrate high pressure gas streams, the packaged short cycle unit for hydrocarbon recovery has appeared only recently. Trends indicate more and more gas producers are purchasing and installing such equipment.

ADSORPTION

Adsorption, as applied to the short cycle hydrocarbon recovery unit, occurs when water and hydrocarbon vapor from wet inlet gas adheres to the surface of a dry desiccant as a gas stream is passed through a bed of the desiccant material. In the adsorption process, water is picked up in the front portion of the desiccant bed. Hydrocarbons pass through and are picked up in that part of the bed which has not been reached by water. The desiccant has a greater affinity for heavy hydrocarbons, such as hexane, than for lighter components, such as butane. In this manner, a gradient of water and hydrocarbons is formed through the desiccant bed.

As adsorption proceeds, water encroaches upon the hydrocarbons in the bed and displaces them. In the same way, heavy hydrocarbons displace lighter ones. Thus, to recover hydrocarbons, the adsorption process must be stopped while the desired constituents still are in the bed.

Thus, it is apparent that for proper operation of a short cycle unit, four basic steps must be accomplished in a short period of time:

1. The adsorbent bed (desiccant) must be saturated to the desired degree.
2. The desiccant bed must be reactivated (the liquid must be removed).
3. The desiccant must be cooled prior to resaturation.
4. Adsorbed products picked up by regeneration gas stream must be condensed and recovered in the stock tank.

OPERATION

The short cycle hydrocarbon recovery unit is fully automatic. All equipment is skid mounted and readily transportable. A flow diagram of one type short cycle unit complete with stabilizing facilities is shown in Figure 1.

In operation, the gas flows from the wellhead to conventional high pressure separators or low temperature separation units (depending on the primary field producing equipment used). Gas from these producing facilities then is picked up and sent to the hydrocarbon recovery unit (Figure 1).

If desired, an operator may install a flow controller on the inlet line to adjust input gas rates. A two-phase or three-phase separator is used as an inlet scrubber to remove any free liquid (which can damage the desiccant)

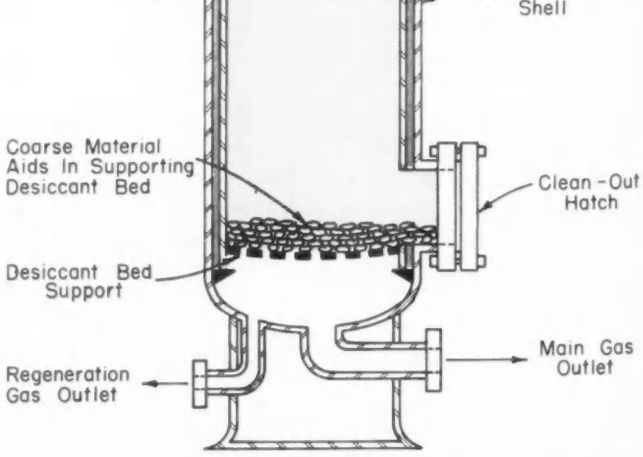


FIGURE 5—Adsorber tower.

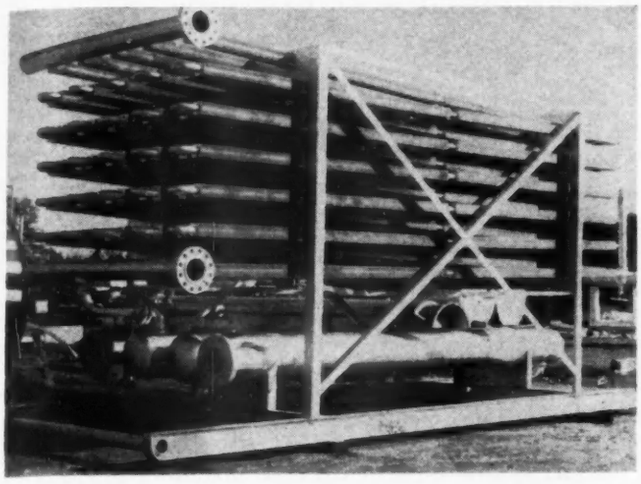


FIGURE 6—Fin type air cooler with gas-to-gas heat exchanger.

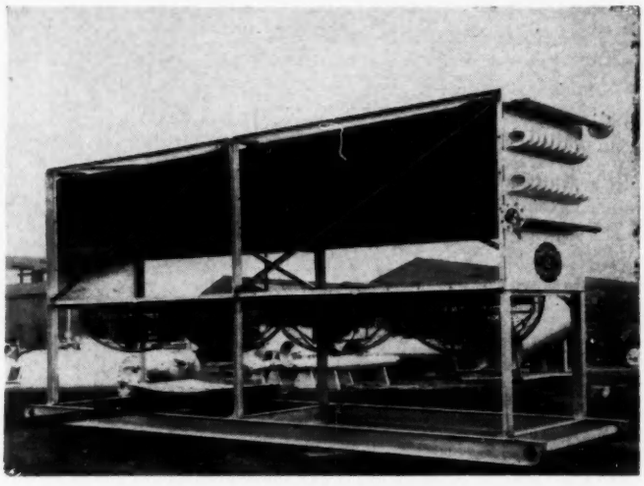


FIGURE 7—Forced draft air cooler.

carried in the inlet gas stream. If a two-phase separator is used, water is separated from the liquid stream in a three-phase surge vessel as shown in Figure 1.

The gas, then, alternately flows through vertical adsorption towers which are packed with dry desiccant, and heavy hydrocarbons are adsorbed on the desiccant bed. The dry, stripped gas is used for final regeneration gas cooling and product cooling prior to entering the sales gas line. While one tower is adsorbing hydrocarbons and water, the other is being reactivated in preparation for adsorption. In the regenerating tower, adsorbed liquids are removed from the desiccant by circulating hot regeneration gas through the bed (Tower 2, Figure 1). The liquids are vaporized and are carried from the tower with the regeneration gas stream.

The regeneration gas stream is cooled by an atmospheric air cooler and a gas to gas heat exchanger, causing vaporized hydrocarbon components to condense. The regeneration gas stream then flows into the regeneration gas scrubber where the liquefied hydrocarbons are collected and dumped to storage (see Equipment Section).

Two types of short cycle units now are in use. One type utilizes what is known as the *open regeneration gas system* while the other type uses a *closed regeneration gas system.*

Open regeneration gas system. Figures 1 and 2 are schematic flow diagrams of units equipped with open regeneration gas systems. As indicated on the diagrams, units may differ in construction.

Referring to Figure 2, the main inlet gas stream is directed into a small regeneration gas scrubber where it is split into a regeneration gas stream and a main stream. Splitter Valve A, located between the regeneration gas scrubber and the combination inlet and regeneration gas scrubber, is actuated by a flow controller installed on the regeneration gas line immediately downstream from the inlet regeneration gas scrubber.

The flow controller is set to deliver a predetermined volume of regeneration gas to the unit. When set for a given flow rate, the controller actuates Valve A which pinches down on the inlet well stream, causing that volume of gas required for regeneration to flow into the regeneration gas system.

The main gas stream passes from the inlet regeneration gas scrubber, through Valve A and into the combination regeneration gas-inlet separator. From there, the liquid-free gas is directed through Valve B into the adsorption tower in service (Tower 1, Figure 2). As the gas passes from the top to the bottom of the tower, water and hydrocarbons are adsorbed by the desiccant bed.

The gas flows out of the tower, through Valve C, through the gas to gas heat exchanger and into the sales gas line. The relatively cool sales gas is directed through the gas to gas heat exchanger to cool the hot regeneration gas stream from Tower 2. A temperature controller may be used to maintain a proper sales gas temperature (Figure 1).

Regeneration gas, which was split from the main stream at the regeneration gas scrubber by Valve A, passes from the scrubber through Valve D into the regeneration gas heater, where it is heated to approximately 600° F. The gas then flows from the heater through Valve E into the tower being regenerated.

Hot regeneration gas transfers heat to the desiccant as it passes through, and adsorbed material is driven from the bed. The regeneration gas stream carries the vaporized material out of the tower and into the air cooler.

In the cooler, regeneration gas and vaporized water and heavy hydrocarbons are partially cooled, and some vaporized hydrocarbons are condensed. For final cooling and condensation, the regeneration gas flows through the sales gas-regeneration gas heat exchanger. The cooled regeneration gas stream then passes to the combination inlet and regeneration gas separator where condensed liquids are separated. Liquid hydrocarbons are dumped to a stabilizer or low pressure separator prior to storage in a stock tank.

When Tower 2 has been stripped of hydrocarbons, controls act to change the position of heater bypass Valve D and cool regeneration gas (at the temperature of the inlet gas stream) is switched to the tower being regenerated (Tower 2). As cool regeneration gas flows down through the hot desiccant bed, heat from the bed is transferred to the gas and is carried from the tower. When the bed has cooled within 30°-40° F. of the inlet gas temperature, controls again act to change the position of all motor valves on the unit.

The main gas stream is switched to the cooled, regenerated tower and regeneration begins on the tower which was on-stream and which has become saturated with water and heavy hydrocarbons.

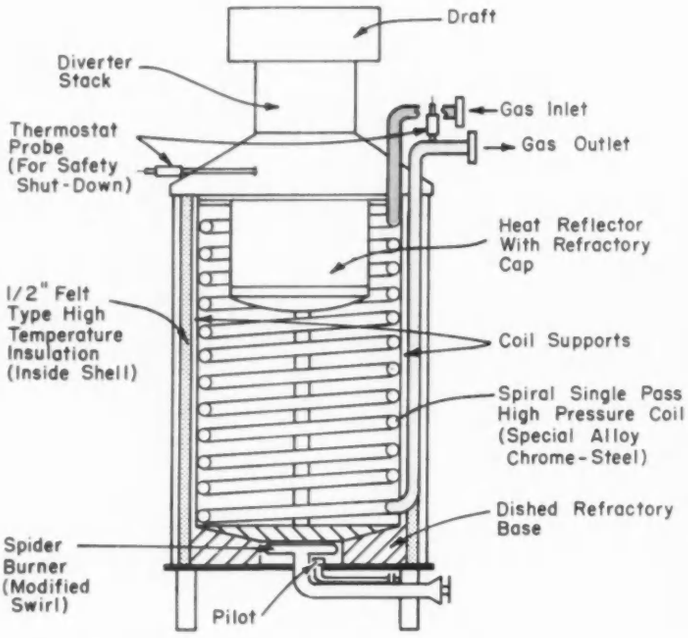


FIGURE 8—Schematic diagram—direct fired heater.

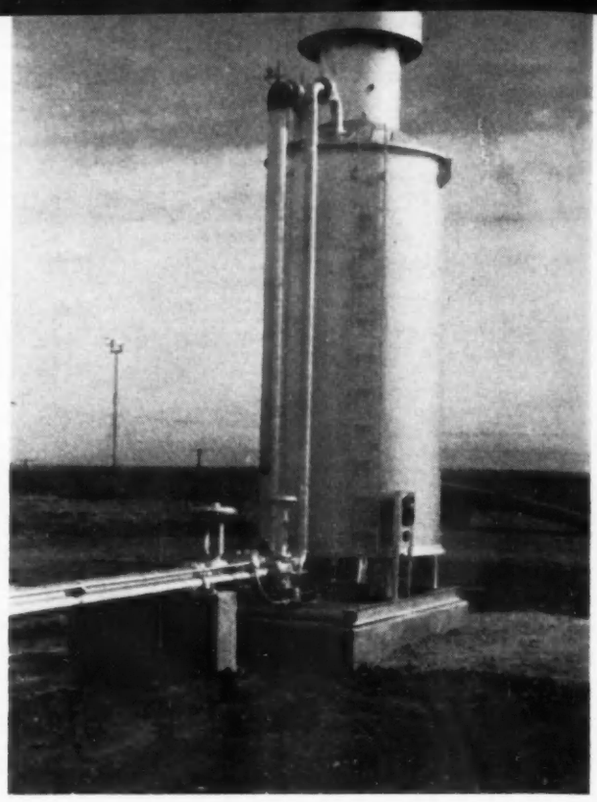


FIGURE 9—Direct fired heater.

Closed regeneration gas system. Figure 3 shows the schematic flow diagram of a unit with a closed regeneration gas system.

►This discussion of the closed system can be traced on Figure 3.

The main gas stream flows into an inlet scrubber where free liquid is removed. The gas flows from the inlet scrubber through three-way Valve A into Adsorber Tower 1 which is the tower in service.

The main gas stream flows down through the tower and water and heavy hydrocarbons are adsorbed as described previously. The stream then passes out the bottom of the tower, through three-way Valve B and into the sales-regeneration gas heat exchanger. From there, dry gas passes to the sales line.

As indicated in Figure 3, a pinch valve is not necessary when using a closed regeneration gas system. Beginning at the outlet of the regeneration gas scrubber, regeneration gas is picked up by an electrically or gas powered blower. Gas is discharged from the blower into three-way Valve C which, in Figure 3, is set so that regeneration gas flows through the heater. After passing through the heater, the regeneration gas flows through three-way Valve D into Adsorber Tower 2, which is the tower being regenerated.

The hot regeneration gas passes through the tower as described previously, out the bottom, through three-way Valve E, through the air cooler and the regeneration gas-sales gas heat exchanger and, finally, into the regeneration gas scrubber where condensed liquids from Adsorber Tower 2 are removed. From there, liquid is dumped into a stabilizer or low pressure separator (see also Figure 1). As the regeneration gas is discharged from the scrubber, the cycle begins over again.

Because of wide fluctuations in pressure in the regeneration gas system due to heating and cooling, a pressure equalizing line is installed between the main gas stream and the regeneration gas system.

As described previously, heater bypass Valve C will switch at the appropriate time and direct cool regeneration gas through Adsorber Tower 2. Once the tower is cooled, all controls will act, and regeneration gas will be directed into Tower 1 while the main gas stream is switched to Tower 2.

The broken line in Figure 3 shows one method of converting a closed cycle unit to an open cycle unit in event of blower failure. Installation of a two-way motor valve (F) is required on the main gas line as shown. When actuated, Valve F will function as a splitter valve. Also, three-way motor Valve G must be installed on the line which connects the regeneration gas system to the main gas system if the switch from closed to open system is to be automatic. Installation of three-way Valve H completes the hook-up.

In event of blower failure, Valves F, G and H will act. Valve F causes a portion of the main gas stream to be directed through the connecting line and into the regeneration gas system through Valve G. Valve H returns regeneration gas to the main gas line. Thus, the unit will operate on an open cycle system. (Note that Valves G and H isolate the gas pump from the system when actuated.)

EQUIPMENT

A typical short cycle hydrocarbon recovery unit consists of the following basic components:

1. Inlet gas scrubber
2. Adsorption towers
3. Regeneration gas cooling equipment
4. Regeneration gas heater, either direct fired or salt-bath

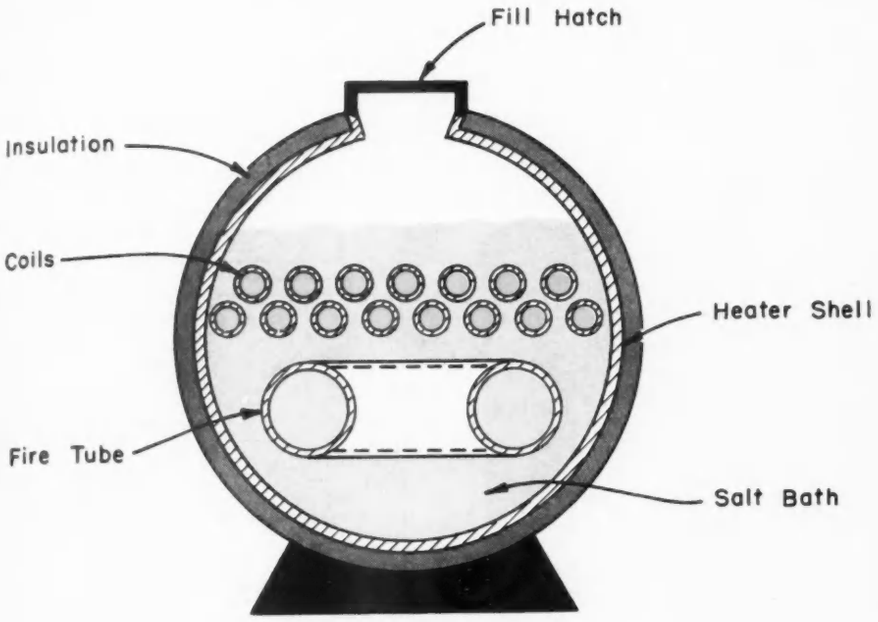


FIGURE 10—Salt bath heater.

5. Regeneration gas scrubber
6. Piping and valving
7. Regeneration gas pump (for use on closed regeneration gas system units)
8. Switching controls and instruments.
9. Optional equipment (low pressure separators, stabilizer, etc.).

Inlet scrubber. The inlet gas scrubber used with the short cycle hydrocarbon recovery unit may consist of a conventional separator or a three-phase vessel. Installation of an inlet scrubber to remove free liquid from the inlet gas stream is necessary since free water and hydrocarbons can severely damage the desiccant bed contained in the adsorber.

If a three-phase separator is used, water is dumped to the pit from the separator while collected hydrocarbons are dumped either to a low pressure separator or to a stabilizer, depending on the installation. If a two-phase separator is used, water is separated from the liquid stream in a three-phase surge vessel as shown in Figure 1.

Some units utilize a three-phase separator which serves both as an inlet scrubber and as a regeneration gas scrubber (Figure 4). Figure 2 shows an installation which uses a combination inlet and regeneration gas scrubber. This combination unit recovers free liquid from the inlet stream and also serves as a separator for the regeneration gas stream which contains condensed hydrocarbons from the adsorber being reactivated.

Adsorption towers. Figure 5 is a schematic drawing of a typical adsorption tower. Towers now in use are equipped with a desiccant support and most have built-in internal insulation. Actually, the tower consists of one shell inside another.

The inner thin walled vessel is insulated from the outer pressure shell by a dead space or by commercial insulating material. Thus, the large mass of steel required for the high pressure outside shell does not have to be heated during each heating cycle. Available information indicates that all short cycle units utilize down flow through the tower; however, internal construction of the vessels differs between manufacturers.

Regeneration gas cooling equipment. Regeneration gas heat loads are much greater on the short-cycle unit than on the conventional long-cycle dry desiccant dehydrator. So additional means must be installed to cool the regeneration gas used in the short-cycle process, since the large heat load cannot be transferred to the sales gas through the normally used gas-to-gas heat exchanger. To compensate for this increased heat load, most manufacturers use a fin-type atmospheric air cooler with a gas-to-gas heat exchanger to adequately cool the regeneration gas stream (Figures 1 and 6).

As indicated in Figure 1, hot regeneration flows from the adsorber tower and enters the air cooler where initial cooling and condensation of hydrocarbons contained in the regeneration gas stream occur. After transferring a large quantity of heat to the atmosphere through the fin type cooler, regeneration gas flows into the regeneration gas-sales gas heat exchanger (bottom, Figure 6).

The regeneration gas-sales gas heat exchanger is of conventional design and is used for final cooling of the regeneration gas stream. Cool sales gas flowing through the shell side of the heat exchanger causes final condensation of hydrocarbons and water to occur in the regeneration gas stream which flows through the tube side of the exchanger.

As mentioned previously, neither an external power source or water supply is required for operation of a short-cycle unit. However, several different combinations of cooling equipment can be used if power and/or water is available.

If power is available, an operator might specify installation of a forced-draft air cooler instead of the atmospheric type and gas-to-gas heat exchanger (Figure 7). Basically, the forced-draft cooler is simply an atmospheric cooler used in combination with a fan which forces air over the cooler elements.

Also, if water is available, a water-cooled tube bundle heat exchanger may be installed in lieu of the gas-to-gas unit (Figure 4).

Regeneration gas heater. Two types of regeneration gas heaters have been used with the short cycle hydrocarbon recovery unit. One is of the direct fired type while the other is a conventional indirect salt-bath unit.

Figures 8 and 9 show one type of direct fired heater used to heat regeneration gas. The heater will provide approximately 600° F. regeneration gas to the adsorber

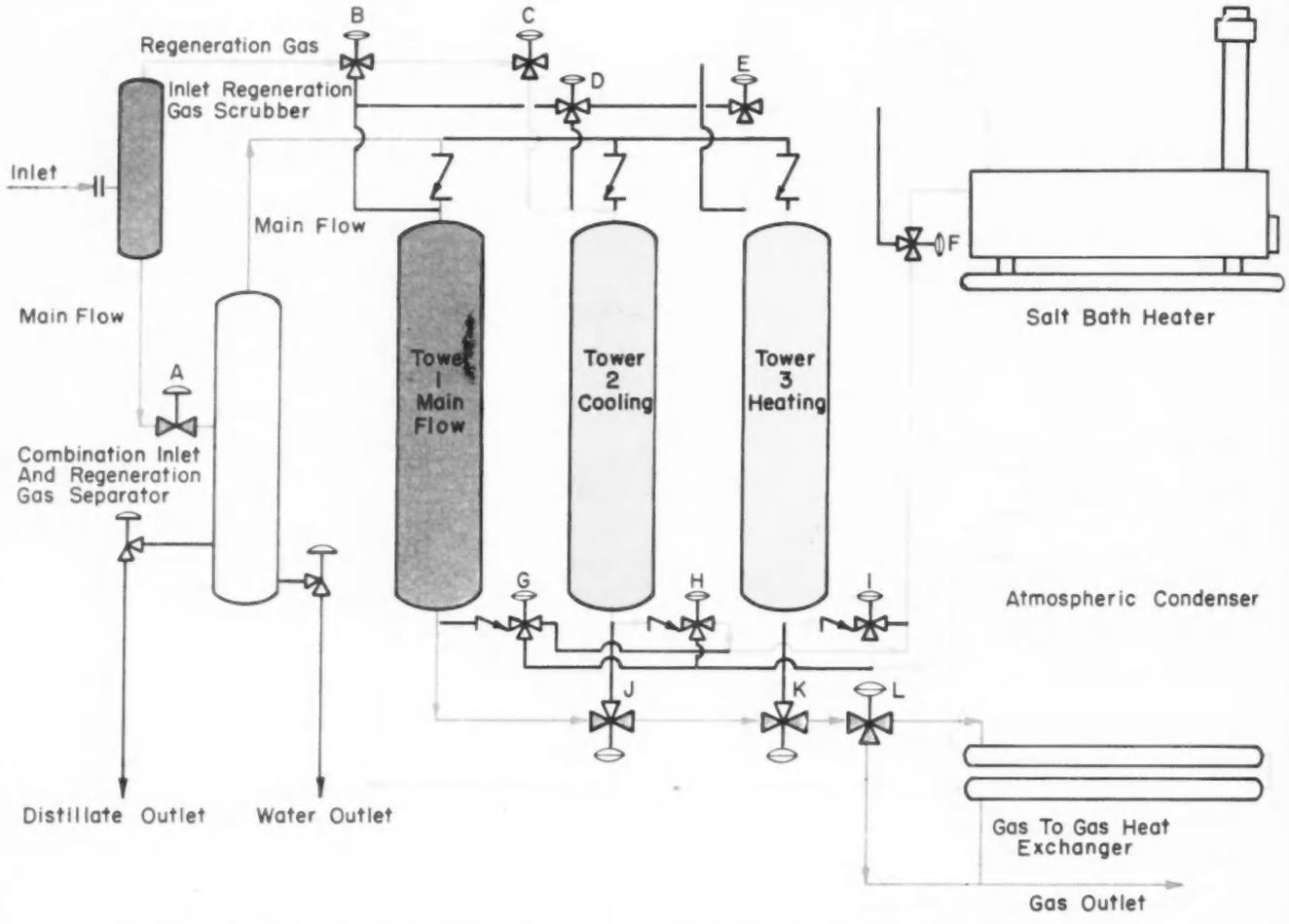


FIGURE 11—Three tower short cycle unit with three-way control valves (open regeneration gas system).

tower upon demand. The burner applies heat directly to the special alloy chrome steel high pressure coils containing regeneration gas. Safety controls, located in the inlet and in the stack of the heater, will shut off fuel gas to the unit should overheating occur.

Figure 10 is a cross-sectional view of a typical salt-bath heater. A flow coil is immersed in the hot salt bath and as the regeneration gas flows through the coil, heat is transferred from the molten salt to the gas stream. Satisfactory regeneration temperatures are obtained with the salt-bath heater.

Regeneration gas scrubber. The term *regeneration gas scrubber* has been used in the past to describe two different pieces of equipment associated with the short cycle hydrocarbon recovery unit, and it has led to some confusion. Normally, the term refers to a two or three-phase separator installed immediately downstream of the gas to gas heat exchanger, which is used to recover condensed liquid hydrocarbons and water from the cooled regeneration gas stream. As shown in Figure 1, two separators could be used in conjunction with the unit—one for recovery of condensed liquids from the regeneration gas stream and one for recovery of free liquids from the inlet gas stream.

As mentioned in an earlier section, some short cycle units (those using one type of open regeneration gas system) use the same three-phase separator vessel to serve both as an inlet gas scrubber and as a regeneration gas scrubber (Figure 2). If this type unit is used, an additional vessel, also referred to as a regeneration gas scrubber, is required (Figure 4).

This vessel is either a large diameter riser on the inlet gas line or a small scrubber vessel through which regeneration gas is split from the main gas stream. The riser is installed so that free liquids from the main stream will not accompany the gas flowing into the regeneration system.

Piping and valving. All equipment used on a short cycle hydrocarbon recovery unit is connected by means of a piping assembly and controlled by diaphragm operated motor valves. Motor valves may be of the three-way or two-way type, and must be positive sealing since any leakage past the valve seat during operation will cause a drastic reduction in operating efficiency.

Valves are controlled automatically by thermostats or time cycle controllers. When thermostats are used, towers are switched when the thermostats signal that a tower has been heated to the proper temperature. When a time cycle controller is used, towers will be switched each time the mechanically set controller actuates the motor valves. Most manufacturers install all control equipment in a centralized panel on the unit for ease of maintenance and operation.

If the regeneration gas heater is installed some distance from the short cycle unit, all hot lines between the unit

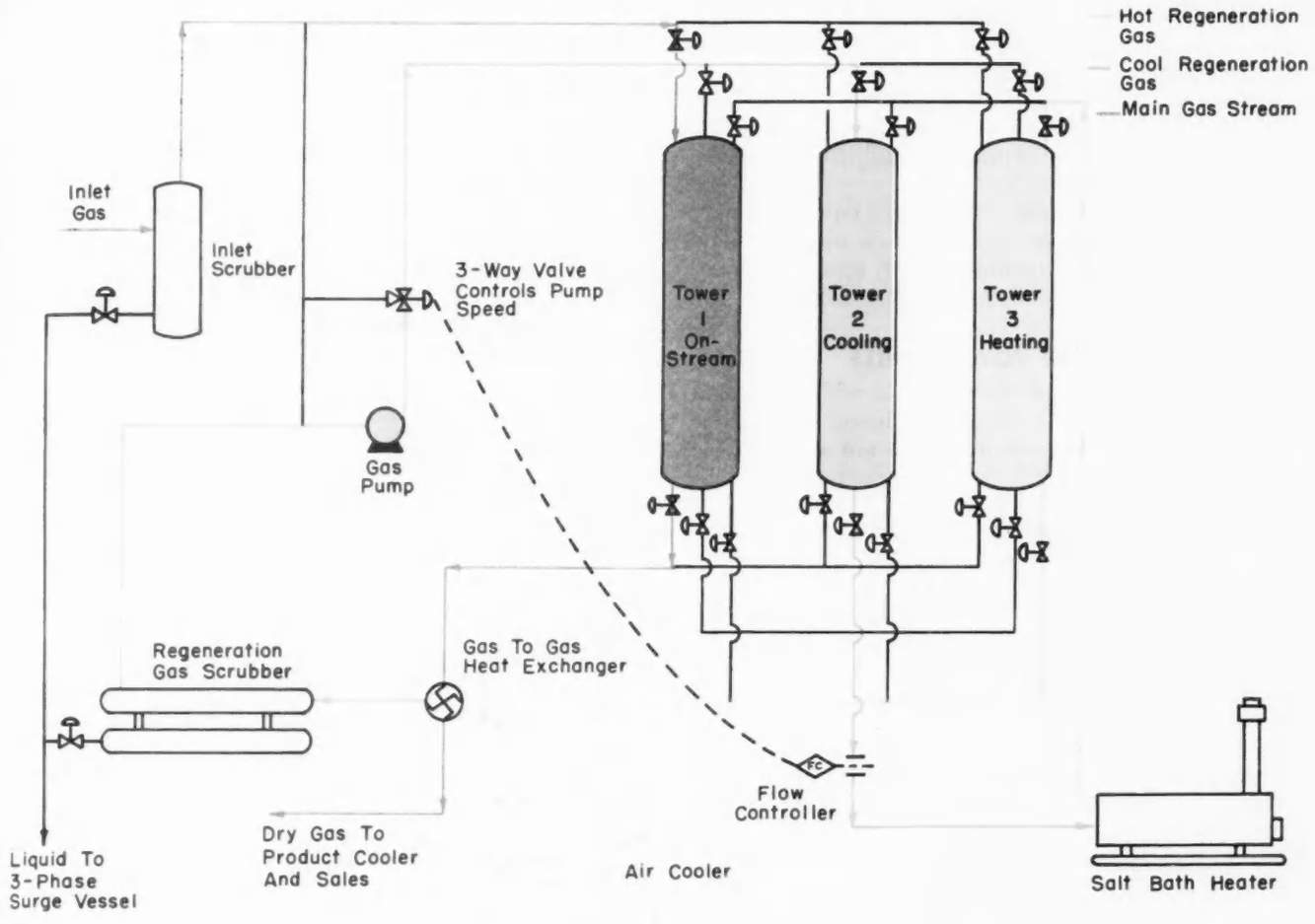


FIGURE 12—Three tower unit with two-way control valves (closed regeneration gas system).

and regeneration gas heater should be equipped with expansion loops and insulated for maximum safety and efficiency.

Regeneration gas pump. Short cycle units which use the closed regeneration gas system require a gas pump or blower for proper operation of the regeneration gas system. The gas blower is the heart of the closed system since it provides the only means of forcing regeneration gas through the unit.

The pump is powered by an electric motor or is driven by gas split from the input gas stream. The gas driven pump may be operated by taking gas through a three-way valve installed on the main gas line. The gas is directed through the driver and discharges back into the main inlet gas line downstream of the three-way valve. One operator has found that a pressure drop of approximately 30 psi is sufficient to maintain proper operating speed on the pump.[1]

If insufficient inlet gas pressure exists so that a pressure drop cannot be taken across the blower, an electric motor or gas engine may be used to drive the unit.

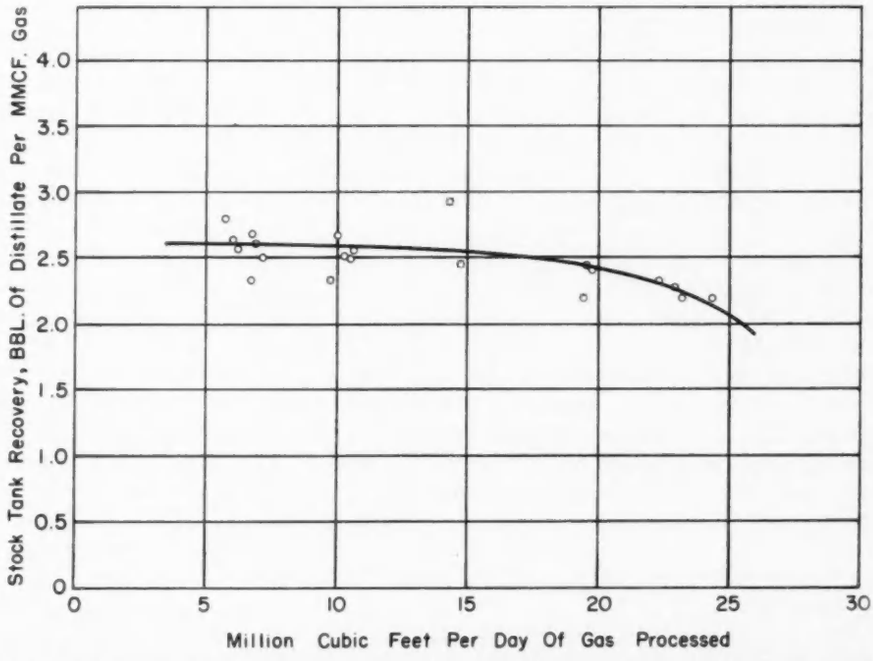


FIGURE 13—Stock tank recovery, barrels per MMcf gas versus MMcf per day of gas processed.[1]

Controls and optional equipment. The subject of controls and instrumentation is a study in itself and no attempt will be made to discuss such equipment here. However, the reader is referred to the instrumentation section (Part 10) of the Production Practices Manual. This section will appear in the March 1960 WORLD OIL and will cover basic field instrumentation.

Many different combinations of optional equipment may be used in conjunction with the short cycle unit (See flow diagrams). Separators, stabilizers and other accessory equipment are covered in detail in other sections of the manual.

MULTIPLE TOWER UNITS

Short cycle hydrocarbon recovery units with more than two towers recently have been introduced. Both three tower and four tower installations now are available.

Three tower units. Three tower hydrocarbon recovery units (Photo E) operate on the same principle as the two tower system; however, the addition of another adsorber tower offers these advantages:

1. A shorter cycle can be maintained, since one tower is adsorbing, another tower is cooling and the third tower is heating—all at the same time. Regeneration cycles as short as 15 minutes may be obtained with the three tower unit.
2. Heater size possibly can be reduced, since regeneration gas is preheated prior to entering the tower.
3. Because of (1) above, less desiccant may be used in the three tower unit than in a two tower unit of the same rated liquid capacity.
4. Fuel consumption is reduced because of the preheating feature mentioned in (2) above.

Additional valving, piping and another tower are required and the cost of a three tower installation is approximately 30 to 35 percent more than the two tower unit of equal gas capacity.[7]

A flow diagram of a three tower installation with an open regeneration gas system is shown in Figure 11. The main inlet gas stream is introduced into the inlet regeneration gas scrubber. Motor Valve A splits the inlet gas stream into two flow paths.

The main flow of gas leaves the inlet regeneration gas scrubber, flows through Valve A and enters the combination inlet and regeneration gas separator, where free liquids are removed. The main gas stream then flows to Tower 1, where hydrocarbons and water are adsorbed. The main stream flows down through the tower, out bottom, through Valves J, K and L into the gas to gas heat exchanger and, finally, into the sales gas line.

The regeneration gas leaves the top of the inlet regeneration gas scrubber, flows through Valve B, and into Valve C, where it is directed into Tower 2 on the cooling cycle. The cool regeneration gas (at inlet temperature) flows down through the tower, out the bottom, through Valves B and F, and into the salt bath heater. There, the regeneration gas is heated prior to entering Tower 3.

As the regeneration gas passed through Tower 2 on the cooling cycle, it was preheated by the hot desiccant bed in Tower 2. The preheated regeneration gas flows through the heater where its temperature is raised to approximately 600° F.

The heated regeneration gas flows from the heater into Valve E and into Tower 3 on the heating cycle. The heated regeneration gas flows through Tower 3, out the bottom, through Valve I and into the atmospheric condenser where initial cooling and condensation occurs.

The gas flows from the atmospheric condenser into the gas to gas heat exchanger for final cooling and condensation of water and hydrocarbons contained in the stream. Liquid and gas then flow to the combination inlet and regeneration gas separator where water and hydrocarbon liquids are separated. The condensate is dumped into a stabilizer or low pressure separator and then to the stock tank. Water is dumped to pit.

This completes the flow pattern for the three tower unit as it appears on one cycle. As soon as the cycle is completed, a time cycle controller acts so that the process is switched. The next step (see Figure 11) would be for the towers to switch with Tower 2 becoming the main flow tower. Tower 3 would begin a cooling cycle and Tower 1 would be heated by the hot regeneration gas and stripped of adsorbed hydrocarbons.

Figure 12 shows a three tower system equipped with two-way motor valves. This unit operates with a closed regeneration gas cycle. The system may be traced by referring to the color code on the drawing.

Four tower units. Some short cycle units with four adsorber towers operate about the same as three tower units. That is, cycles are arranged so that two towers are onstream, one tower is being heated and one is on a cooling cycle at the same time. Adsorber vessels may be smaller than those used in units with fewer towers, and less desiccant is required to process a given volume of gas.

Other four tower units are designed to recover lighter fractions (propanes, butanes) from the gas stream (Photo F). One such unit uses two towers filled with silica gel and two filled with activated charcoal. The silica gel-activated charcoal towers operate in series. That is, one silica gel and one activated charcoal tower are onstream at the same time. Principal use of this system has been in recovery of LPG fractions.

TROUBLE-SHOOTING

Most operators using short cycle units have encountered few major difficulties once a unit has been placed onstream and properly adjusted. Table 1 includes the chief operating difficulties experienced by six producers which have several short cycle units in service. As indicated, direct fired heater coil failure and gas pump failure have been the most prevalent mechanical difficulties.

The majority of the operators who reported coil failures stressed that the trouble occurred in early heater models which utilized split flow coils. Since the earlier units were installed, improved quality control, more stringent pressure testing procedures and better coil design have measurably improved the performance of the direct fired unit. With proper maintenance of heater safety controls, there should be no reason why current direct fired units should not operate trouble-free.

Blower lubrication system trouble and resulting blower failure have been indicated as frequent sources of trouble. However, one operator reported satisfactory gas pump performance for a 1½ year period. At the end of this time, the blower bearings and seals were replaced. Other producers have reported favorably on efforts to improve blower lubrication systems and some have reduced the problem to a relatively minor trouble.

It is of interest that only one of six operators has re-

ported a required desiccant change. It is thought that amines associated with corrosion inhibitor treatments were responsible for this replacement.

Many units which have been operating from 1½ to 2 years still are performing satisfactorily with the original desiccant charge. Although some operators use an estimated desiccant life of 1½ years for payout calculation purposes, there has apparently been no hard and fast rule set as to the frequency of desiccant replacement.

In Table 1, there were no reports of leakage trouble with diaphragm operated control valves because of operating conditions. With proper adjustment and lubrication, valves apparently will perform satisfactory for an indeterminate period of time.

Operator B (Table 1) reported some problems in controlling regeneration gas blower speed. This problem usually occurred during periods of cold weather. It was thought that hydrates in the control line to the gas powered blower were responsible, and the problem was minimized by installing drip pots filled with silica gel on the sensing lines to the pump speed control.[1]

One operator reported difficulty in obtaining a stabilized liquid product which will conform to predetermined specifications. The variable product resulted because of surging conditions from separators on the unit. This problem was minimized by installing a larger surge vessel upstream of the stabilizer (Figure 1).

Most operators have experienced difficulty in obtaining a representative sample of the sales gas discharged from short cycle units. Composition of the outlet gas varies considerably because of the properties of the desiccant bed at different times in the adsorption cycle. For example, when a freshly regenerated tower is placed onstream, there is a tendency for light as well as heavy hydrocarbons to be adsorbed. During the latter part of the cycle, only the heavier ends are adsorbed and outlet gas composition changes.

To solve this problem, one operator recommended that exit gas be sampled at a constant rate by water displacement over several complete cycles. Although this method is not satisfactory in all cases, some operators prefer it to others.

As an example of varying gas composition, some operators have found that sales gas leaving the unit contains a higher percentage of propanes than was contained in the main inlet gas stream. This usually occurs during one specific portion of the adsorption cycle and apparently results for two reasons:

1. On open cycle units, condensed propanes in the regeneration gas stream are re-introduced into the main gas flow just prior to entering the inlet gas scrubber. If the inlet stream is sampled upstream of the unit, a false propane content of the gas actually entering the adsorber tower is obtained.
2. Propanes previously adsorbed on the bed early in the adsorption cycle are displaced by heavier hydrocarbons during the latter portion of the cycle. This results in a high propane content in the outlet gas for a short period of time.

RECOVERY

Although liquid recovery will vary with operating conditions (adsorbent properties, temperature, pressure, inlet gas composition, etc.), it is of interest to note one producer's experience.

TABLE 1—Short-Cycle Hydrocarbon Recovery Unit Operational Difficulties

Operator	Operating Difficulties
A	(1) Coil failure in direct fired heaters. (2) Difficult to obtain representative sales gas sample
B	(1) Blower bearing failure after 1½ years operation (2) Coil failure in direct fired heated (3) Difficulty in controlling blower speed (4) Difficult to obtain representative sales gas sample
C	(1) Difficult to obtain representative sales gas sample No other operating difficulties were reported
D	(1) Faulty blower lubrication system (2) Coil failure in direct fired heater (3) Difficult to obtain representative sales gas sample
E	(1) Difficult to obtain representative sales gas sample No other specific difficulties have been reported
F	(1) Faulty blower lubrication system (2) Desiccant failure due to amines from corrosion inhibitor treatment (3) Difficult to maintain liquid product which will conform to specifications (4) Difficult to obtain representative sales gas sample

TABLE 2—Hydrocarbon Recovery From Short Cycle Unit[1]

Component	Inlet Gas Mole Percent	Sales Gas Mole Percent	Unit Liquid Mole Percent	Flare Gas Mole Percent	Stock Tank Liq. Vol. Percent
C_1	95.89	96.15	20.12	68.50	0.00
C_2	2.66	2.66	4.01	13.76	0.00
C_3	.75	.74	4.27	10.14	1.18
iC_4	.17	.16	2.44	2.92	1.77
C_4	.20	.19	3.20	3.02	2.51
iC_5	.07	.06	3.56	1.37	4.06
C_5	.04	.03	3.13	.28	3.45
C_6+	.22	.01	49.27	.01	87.03
Quantity	20,351 MCFGPD	20,282 MCFGPD	59.0 bbl/day	20.86 MCFGPD	48.8 bbl/day
Pressure	820 psig	795 psig	795 psig	280 psig	Atmosphere (10.6# RVP)

Table 2 is a summary of liquid recovery from a short cycle unit. At the inlet flow rate, there was 0.33 mol percent (3.16 bbls.) of iC_5 + per MMcf of gas entering the unit. As indicated in Table 2, 48.8 barrels per day of liquid (2.40 barrels per MMcf) were recovered in the stock tank. Thus, approximately 76 percent of the inlet pentanes plus fraction were recovered.[1]

Figure 13 relates stock tank recovery to MMcf of gas processed. The downward slope of the curve is thought to be due to errors in stock tank gaging. This particular unit has since operated satisfactorily at a rate slightly in excess of its rated liquid and gas capacity.[1]

ACKNOWLEDGMENT

Figure 13 and Table 2 were originally published in the paper *Operations of a Dry Desiccant Type Hydrocarbon Recovery Unit* by Q. S. Drake and E. R. Dawson. (See *Literature Cited.*)

LITERATURE CITED

[1] Drake, Q. S. and Dawson, E. R., *Operations of a Dry Desiccant Type Hydrocarbon Recovery Unit*, presented at Oklahoma Regional Meeting, Natural Gasoline Association of America, Oklahoma City, January 1959.

[2] Plitt, Fred H., *How to Determine Payout of Wellhead Adsorption Units*, World Oil, Page 120, June 1959.

[3] Ebeling, H. O. and Heumann, J. R., *Comparison of Hydrocarbon Recovery Process—Refrigeration vs. Dry Desiccant*, presented at a meeting of the AIChE, Dallas, May 1959.

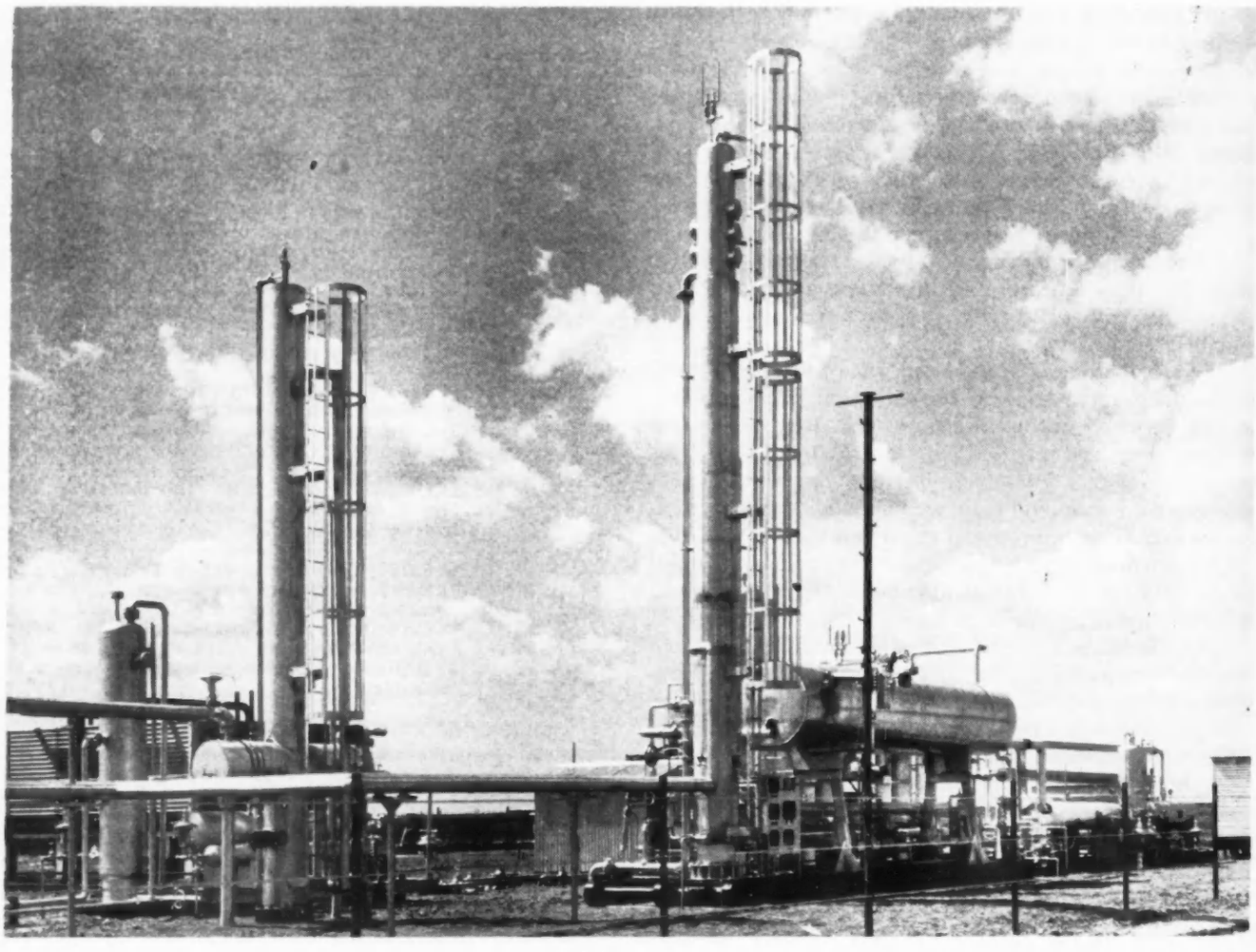
[4] Dow, W. M., *Adsorption—The Process to Watch*, Petroleum Refiner, Page 141, April 1957.

[5] Dow, W. M., *Gasoline and LPG Recovery From Natural Gas By The Adsorption Process*, presented to the Rocky Mountain Regional Meeting, NGAA, Casper, Wyo., September 1958.

[6] *Technical Bulletin 202*, Davison Chemical Division of W. R. Grace & Co.

[7] Mapes, G. J., C_5^+, *The Hidden Gold in Natural Gas*, Parkersburg Rig and Reel Co. House Organ.

[8] Bulletin 33-111, Black, Sivalls & Bryson, Inc.



This low temperature separation installation is equipped with an ammonia absorption refrigeration unit. The unit provides the cooling effect normally furnished by reducing the pressure of the gas stream by means of a choke. The photograph shows the stabilizer (left), ammonia unit (center) and low temperature separation equipment (right).

7. THE AMMONIA ABSORPTION REFRIGERATION UNIT

By J. Roger Heumann, Technical Service Specialist
Black, Sivalls & Bryson, Houston

LOW TEMPERATURE SEPARATION is a widely accepted method for field processing of gas. Both hydrocarbon liquid recovery and dehydration of sales gas can be accomplished by this one process. Normally, application is limited to high pressure gas-condensate streams where pressure drop can be used to obtain the refrigeration effect and the condensate recovered can pay out equipment cost rapidly.

A natural advancement in the process has been the use of mechanical refrigeration in place of the choke on rich streams where a large pressure drop is not available. It is to be expected that early installations should utilize equipment already available and in common use by the food and air conditioning industry.

Several years ago, a packaged refrigeration unit was introduced which was designed specifically for the rugged conditions found in oil field operations. To assure satisfactory operation, the system was designed for the same dependability as the separators, heat exchangers and stabilizer used in conjunction with it.

An ammonia absorption refrigeration cycle was selected to eliminate the compressor required in most refrigeration systems. The ammonia is absorbed in water, which in turn is pumped into a still column where the ammonia is distilled and condensed. The absorption method of refrigeration has increased the dependability of the low temperature process for field operations, decreased maintenance problems and improved operating characteristics (Figure 1).

Figure 2 shows a flow diagram of the compression and absorption refrigeration cycles.

The well stream flow. Figure 1 shows a typical hook-up for a low temperature unit using ammonia absorption refrigeration. The well stream to be processed flows through the inlet scrubber for separation of free water; then to the heat exchangers where it is cooled by the low temperature separator off-gas. Normally, the gas would now pass through a choke before entering the low temperature separator. In the case illustrated, however, choking cannot be used since a large pressure drop is unavailable. Therefore, the gas passes through the chiller where the temperature is reduced, usually to 0° F or below, and then flows into the low temperature separator.

Condensate from the separator is sent to the stabilizer while the cold off-gas is returned to the shell side of the well stream heat exchanger. Glycol is injected into the gas stream to prevent hydrate formation and is recovered from the low temperature separator for regeneration.

THE AMMONIA REFRIGERATION PROCESS FLOW

With the exception of the chiller, the process flow described previously has been used for many years. In discussing the ammonia refrigeration unit, it should be kept in mind that its only purpose is to furnish refrigerant to the chiller in order to produce the low temperature desired.

In addition to the chiller, the ammonia absorption refrigeration unit consists of the ammonia absorber, still charge pumps, feed-bottoms heat exchanger, ammonia still, still reboiler, and the ammonia condenser. Figure 3 shows a typical ammonia absorption unit.

The chiller. The purpose of the chiller is to remove heat from the well stream and consists of a tube bundle or flow coil immersed in a bath of boiling liquid ammonia (Figure 4). The tube bundle is in the lower half of the chiller shell, allowing the upper half of the shell to serve as a vapor disengaging space. When the shell-side pressure is approximately 9 psig, the temperature of the ammonia bath is —10° F. When the unit is shut down, the chiller will warm up to atmospheric temperature and pressures within the unit equalize. This requires that the chiller shell be designed for 265 psi pressure even though it normally operates at 9 psig.

The ammonia absorber. Ammonia vapor from the chiller is absorbed by a fine spray of ammonia-lean water solution in the absorber (Figure 5). Cooling water circulating through a tube bundle in the lower half of the absorber removes the heat of absorption as rapidly as it is evolved. The absorber operates at a pressure only slightly lower than the shell-side chiller pressure—about 9 psig.

Still charge pump. The still charge pump is the unit's only moving part. Its function is to take suction from the bottom of the absorber at 9 psig, pumping the ammonia-rich water solution through the feed-bottoms heat exchanger and into the still column which operates at 215 psig.

Feed-bottoms heat exchanger. This fixed-tubesheet shell-and-tube heat exchanger preheats the ammonia-rich

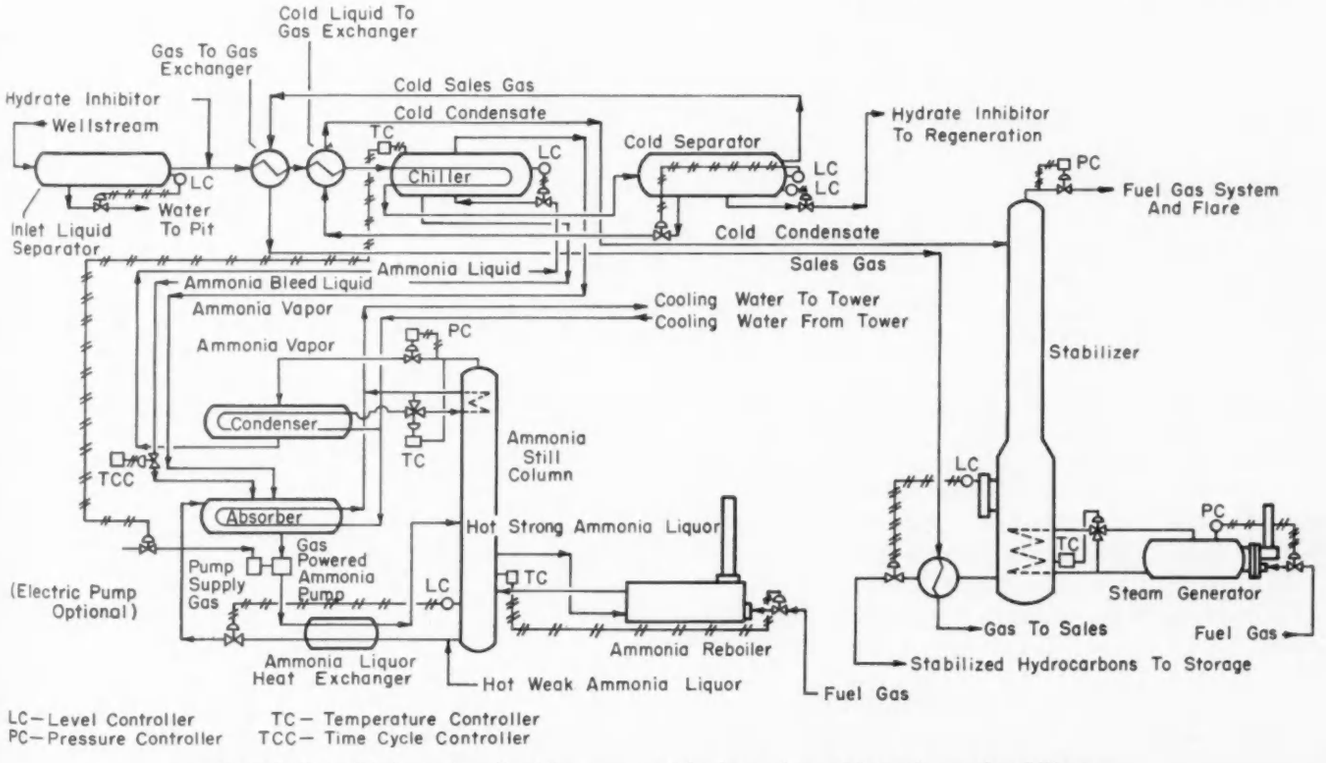


FIGURE 1—Hydrocarbon liquid recovery with absorption refrigeration and stabilizer.

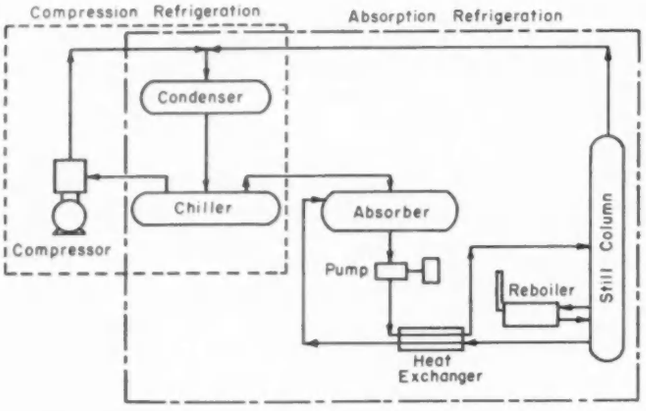


FIGURE 2—Flow diagram for compression and absorption refrigeration.

water solution being pumped into the still while cooling the ammonia-lean water solution coming from the bottom of the still column.

Ammonia still column. The still column or bubble tray column operates at 215 psig and effects the separation of ammonia from water (Figure 6). A salt bath heater serves as the still reboiler while a partial condenser in the top of the still furnishes reflux without the need for a reflux pump.

The ammonia-lean water solution leaves the bottom of the still and is cooled in the feed-bottoms heat exchanger before being discharged through the still bottoms level control valve. The cooled solution from the heat exchanger is filtered to remove all particles of scale or rust before being sprayed into the absorber where it again contacts the ammonia vapor from the chiller, completing the process cycle.

Ammonia final condenser. Ammonia vapor leaving the top of the still column through a conventional pilot-operated back pressure valve is liquefied in the water cooled condenser (Figure 7). The condenser tube bundle is in the top half of the horizontal condenser shell, leaving the lower half to serve as the liquid ammonia surge drum. The liquid ammonia is returned to the chiller by means of a level controller sensing the ammonia level in the chiller.

OPERATING CHARACTERISTICS

Both process characteristics and equipment design are well suited to field conditions. As shown in Figure 8, the ammonia absorption unit can operate over a wide range of chiller temperatures with only a small change in capacity.

A second characteristic, valuable in any field unit, is the ease with which the process can be controlled. The chiller temperature can be controlled by the rate at which ammonia vapor is removed from the chiller. This is a function of the still charge rate. Therefore, a temperature controller sensing the chiller temperature can be used to control the still charge pumping rate. This control will adjust the unit automatically from no load to full load.

Other controls on the unit will adjust according to the demands of the chiller. Varying the still charge rate results in fuel consumption being directly proportional to the load on the unit. It is important to note that sensitive response is not critical since the process will allow considerable deviation from the control point without significantly upsetting the unit.

Normal load changes are handled easily by the automatic controls but slugs of liquid entering the chiller can cause process upsets which may take the unit some time to overcome. If an upset should cause liquid ammonia to "slop over" from the chiller, no harm is done to the unit.

The dependability of the ammonia absorption unit is one of its most outstanding characteristics. This feature is of prime importance for unattended operation.

Mechanical features aid field operations. When a unit is designed for the oil field, consideration should be given to the availability of materials as well as the availability of operating and maintenance labor. When charging the ammonia absorption refrigeration system initially, clean, fresh water, suitably treated with a corrosion inhibitor, is used as the absorbent. There is no need for high purity ammonia in this unit. Fertilizer grade ammonia, available in most farming communities, is suitable and sells for only a fraction of the cost of the refrigeration grade.

All controls used on the system would be familiar to any pumper or roustabout experienced in operating other field equipment. Since the ammonia absorption refrigeration unit is only a part of the low temperature process equipment, the use of standard oil field controls simplifies stocking of spare parts.

Safety devices are few since the process is inherently safe. However, certain safety controls have been installed to insure adequate protection of equipment when operating on an unattended basis. Dual safety relief valves designed for ammonia service are used on each vessel. Also, the vessel is supplied with a special manifold which allows

We Need Your Help

WORLD OIL's staff is pleased to report that subscriber response to the Production Practices Manual on Producing Equipment for Natural Gas Wells was immediate and enthusiastic. Many requests for the manual in reprint form have been received.

We want to comply with these requests. But first we must determine the number of reprints to publish—and that is where you can help.

Although we cannot accept orders as yet, if you are interested in obtaining a copy of the manual, at nominal cost, please send a postcard or note to Engineering Editor, WORLD OIL, P. O. Box 2608, Houston, Texas. Or, if you prefer, indicate your interest on the Reader's Service Blue Postcard inside the back cover of this issue, fill in your name and address, and drop the postage-paid card in the mail.

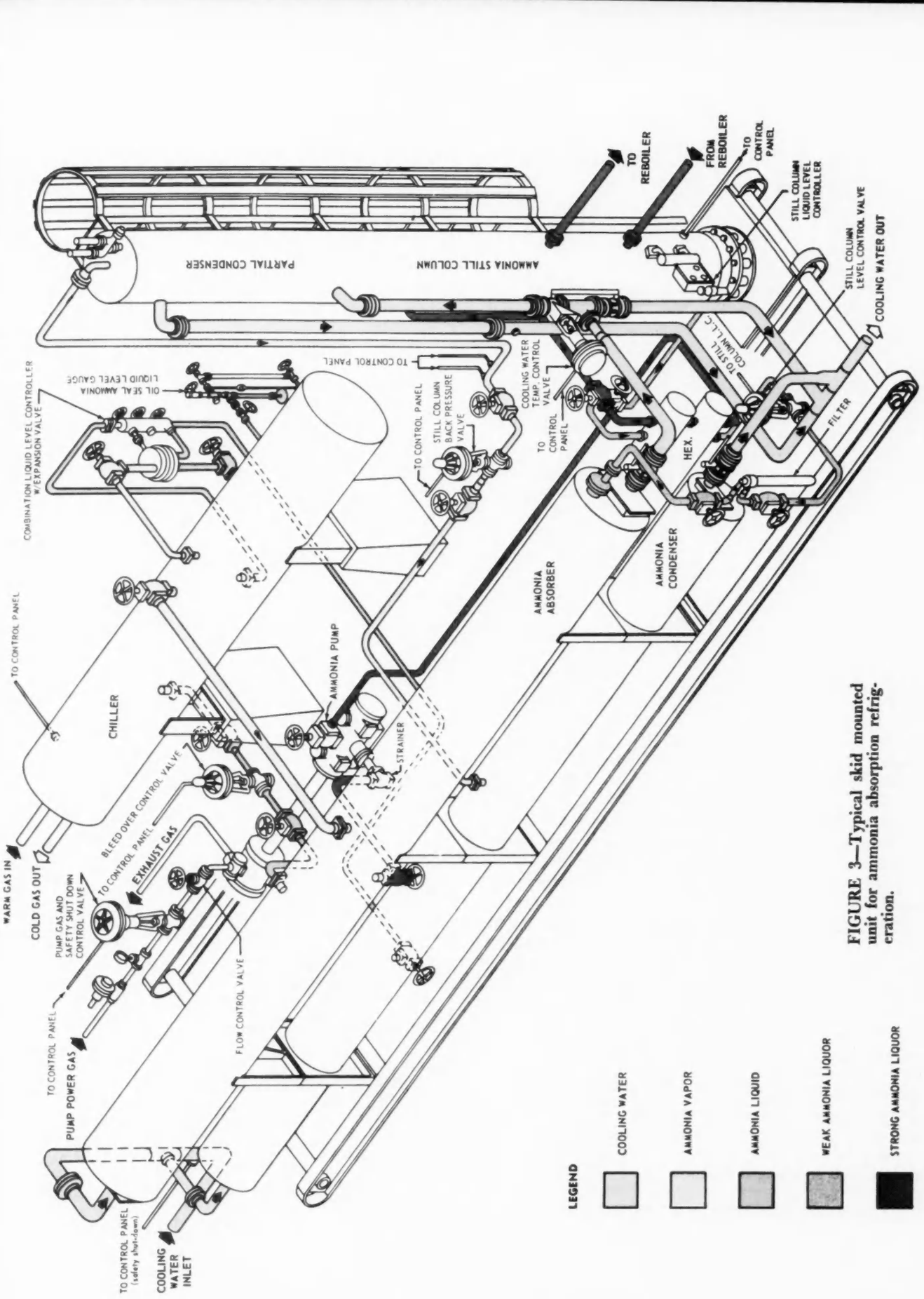


FIGURE 3—Typical skid mounted unit for ammonia absorption refrigeration.

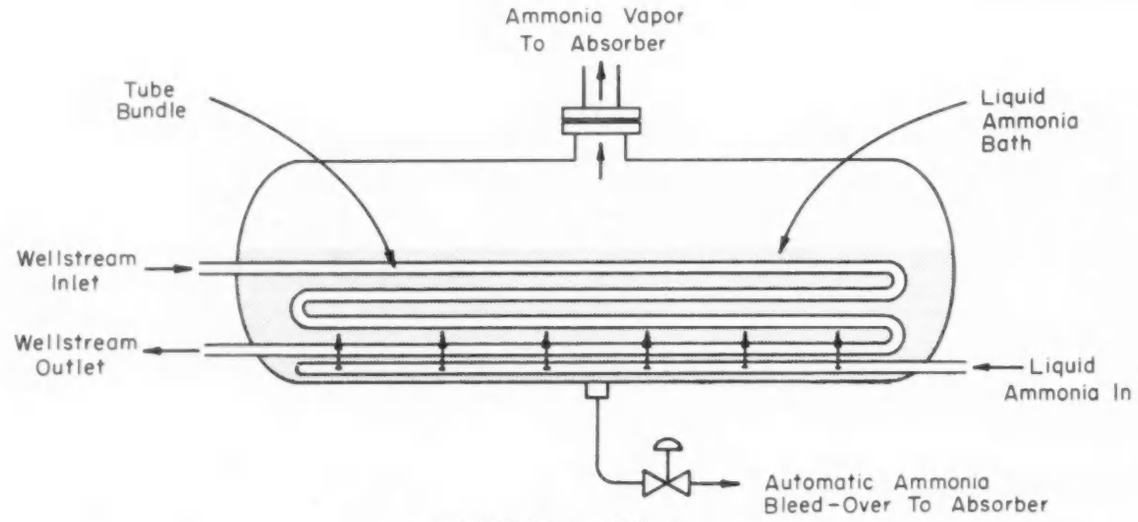


FIGURE 4—Chiller.

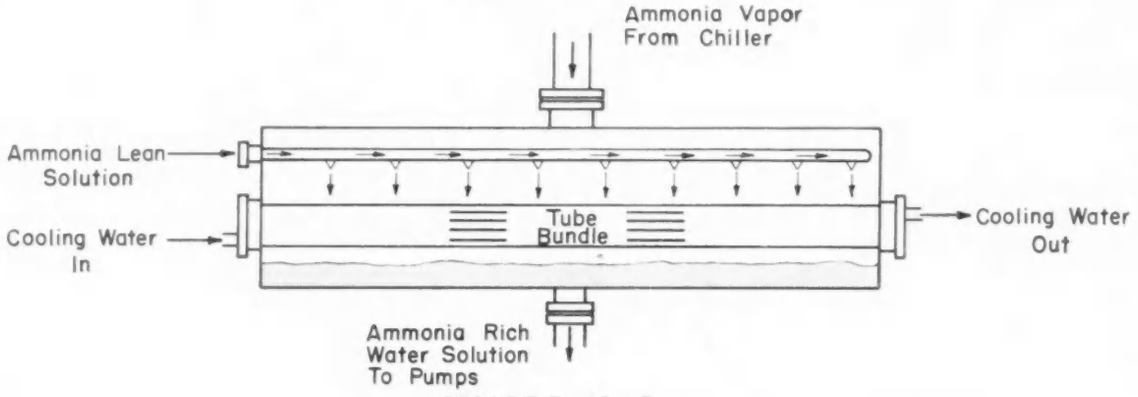


FIGURE 5—Absorber.

either relief valve to be removed from service without shutting down the unit.

A high temperature shutdown control and pilot flame failure shutdown are included on the reboiler. A fourth safety control shuts the ammonia unit down in case of cooling water failure. When cooling water circulation is restored, the ammonia unit will resume operation automatically.

Hand valves used in the system are designed specifically for ammonia service and are of the back-seating type. This allows the valves to be repacked under pressure since the seat seals the packing gland from the fluid in the valve.

With the exception of the still, all vessels are horizontal and lend themselves readily to skid mounting up to the 100 ton capacity size. The still column is short—about the same height as an emulsion treater. Since the charge pump is the only part of the basic unit which moves, no vibration occurs. These factors make it possible to use the simplest of foundations, another important consideration is selecting field units.

TROUBLE SHOOTING THE AMMONIA UNIT

A reasonable amount of preventative maintenance by the pumper can forstall the majority of operational problems.

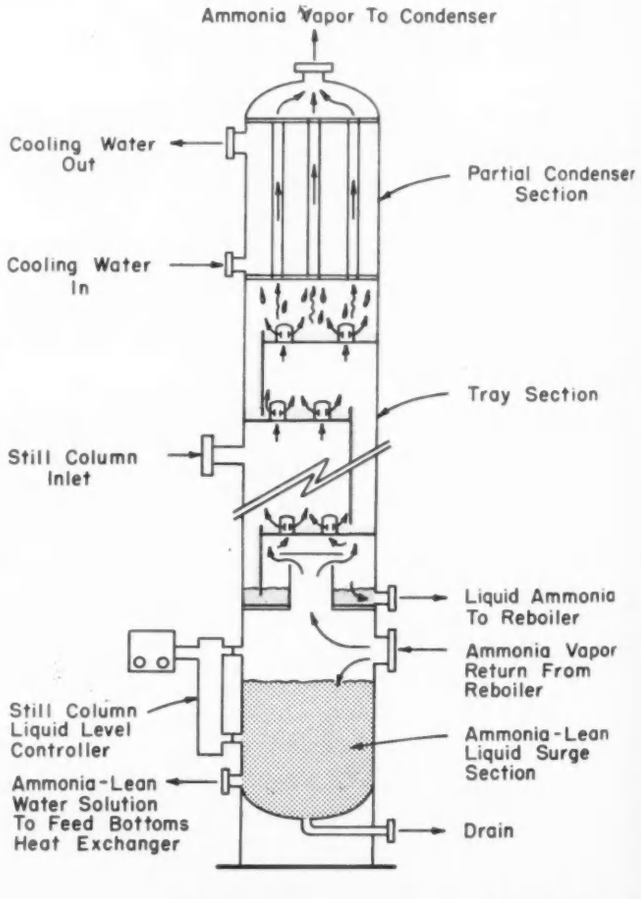


Figure 6—Still column (right).

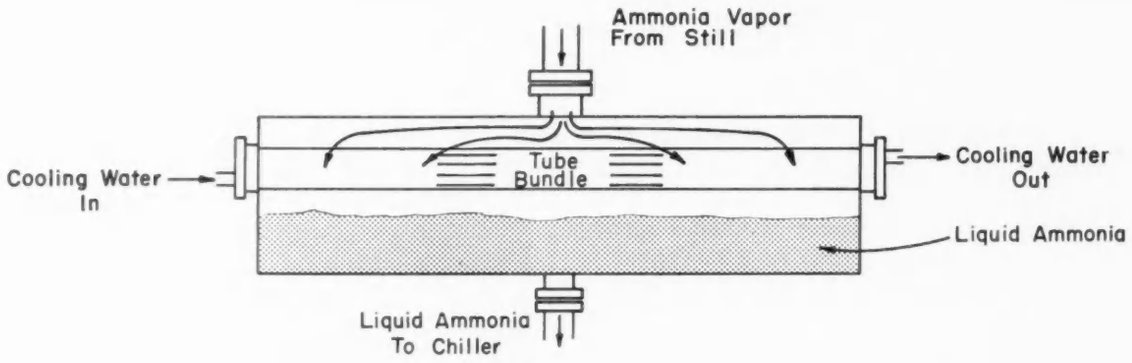


FIGURE 7—Condenser.

Since the unit is water cooled, some water treatment generally is required. The presence of scale, mud, weeds, or algae in the absorber and condenser tubes will reduce the capacity of the unit. Evidence of such fouling will be indicated by difficulty in holding the still overhead temperature, an increase in condenser pressure and an increase in absorber temperature.

Vapor-locking of the still charge pump will result if the suction strainer is not cleaned regularly. This is particularly important when the installation is new. The filter provides for the absorber spray nozzles also must be cleaned as a matter of routine. A differential pressure of 20 to 30 psig indicates a need for cleaning the filter element.

Ammonia is difficult to contain. Therefore, pump packing and valve packing must be kept in good condition. Failure to maintain the packing will allow ammonia and water solution to leak from the system. This will result in a lower water level in the absorber and a lower ammonia level in the final condenser.

Occasionally, the water level in the absorber will become lower without any apparent system leaks. The water may have been gradually distilled overhead in the still column and eventually ended up in the chiller.

Under normal operation, ammonia vapor from the still contains only one-tenth of one percent water. Over a long period of time this water will build up in the chiller and result in gradually increasing chiller temperatures. An automatic bleed-over valve is provided to "blow-down" the chiller to the absorber and prevent this water build up. An insufficient bleed-over rate or sudden still column upsets may require an increase in the bleed-over.

Over a long period of time, non-condensible gases will form from the results of corrosion and decomposition due to reaction with impurities in the metal. Also, air may be pulled into the unit through faulty pump packing. These gases will slowly accumulate in the condenser and absorber and must be vented to the atmosphere. Venting of the condenser may be indicated if the condenser requires an excessive amount of cooling water. If it is not possible to obtain low enough temperatures in the chiller, the absorber may need venting.

LIMITATIONS

Like most equipment, the low temperature gas processing system must compete with other processing methods. On initial cost, the ammonia absorption refrigeration system will be a bit more expensive than compression type units in sizes smaller than 50 tons capacity or when chiller temperatures are above 0° F.

Cooling water is not always available and the ammonia absorption unit requires a circulation rate of seven gallons per minute per ton of capacity. This means a fresh water make-up volume of 2 to 2½ percent of the circulation rate. Air cooling can be used, but the additional cost of equipment may be as much as 25 percent to 40 percent over the cost of the water cooled unit.

Fuel consumption is greater for the ammonia absorption refrigeration system than for the compression type unit but is usually much less than a comparable oil absorption gasoline plant.

The ammonia absorption equipment is bulky although space is seldom a factor in field installations.

APPLICATIONS

The ammonia absorption refrigeration unit is only a part of the equipment required to process a given gas stream—that is, it is the means of producing the refrigeration and not a method of handling gas. The use of artificial refrigeration in the oil field is only beginning. In large gasoline plants, the use of chilled lean oil is showing increased popularity.

Figure 1 shows a typical low temperature field installation designed to recover a stabilized product and dehydrate the sales gas. The stabilized condensate produced brings a better price in some areas than wild condensate produced from stage separation equipment.

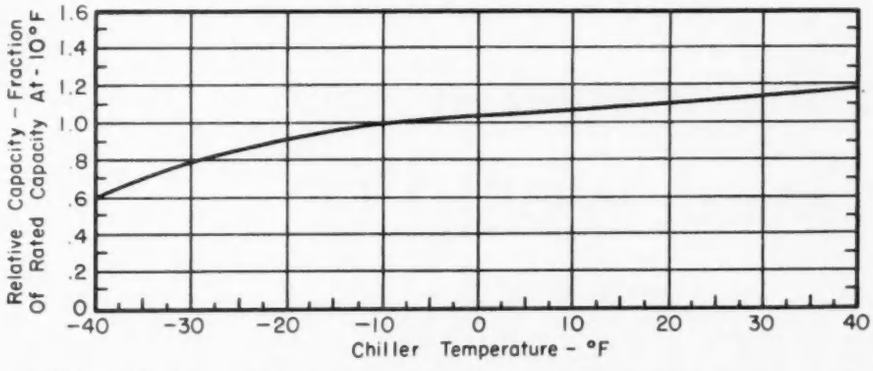


FIGURE 8—Absorption refrigeration relative capacity vs. chiller temperature.

In some cases, this system is finding application where the propane-butane rich stream obtained from the stabilizer overhead can be used in enriched gas drive projects.

It is important to recognize that several chillers can be handled by one basic refrigeration unit. Thus, several different streams at varying pressures can be processed economically without commingling.

If total liquid production warrants a more elaborate plant, the raw liquid produced can be fractionated to obtain commercial propane and butane as well as natural gasoline.

The low temperature process would be ideal for processing gas being used in gas lift operations or reservoir injection wells. Economically, the low temperature process will find greatest use on rich streams such as gas-condensate wells or compressed treater gases. Present installations of low temperature units using a choke can be converted to ammonia absorption refrigeration when reservoir pressures decline. The chiller merely substitutes for the choke and the rest of the equipment remains the same as before.

The present trend toward use of specialized production units emphasizes the need for careful application of equipment. The low temperature process is no exception to this rule. While it is mechanically flexible and can be used on virtually any gas stream, each application should be carefully scrutinized from an economic standpoint in order to obtain the maximum return on money invested.

LITERATURE CITED

[1] Comparison of Hydrocarbon Recovery Processes—Refrigeration Versus Dry Desiccant, H. O. Ebeling and J. R. Heuman, presented at May 26, 1959 meeting of the District AIChE, Dallas.
[2] Ammonia Absorption Refrigeration Selected for Gasoline Plant, Whit Downer, *Petroleum Engineer*, July, 1957.
[3] Vapor Retention From Low Temperature Gas Processing Units, R. E. McMinn and Colman Fisher, presented at district meeting of the API, May 6-8, 1959, Casper, Wyo.

Watch for
the concluding
installment of
this manual in your
March WORLD OIL

INTERNATIONAL

Prospecting in Southern Algeria

These outcrops are on the surface exposure of the In Guezzam anticline in the extreme southern Algerian portion of the Sahara. They are believed to consist of Cambro-Ordovician sandstones. These beds indicate the widespread occurrence of Cambro-Ordovician sandstones. Sands of the same approximate age as those shown here are productive in Hassi-Messaoud, Hassi R'Mel and other central Sahara fields, and in the Edjele-Zarzaitine vicinity in extreme eastern Algeria. The In Guezzam structure is located about 280 miles south of Tamanrasset (Fort Laperrine).

Drilling in Puerto Rico

The first attempt in Puerto Rico's history to drill for oil began last November in a field of sugar cane near the small town of Santa Isabel on the south coast of the Caribbean commonwealth. Backers of the venture are Texas investors headed by David L. Gordon, president of Maritime Oil Company. On the basis of geological studies, drillers hope to find oil-bearing formations not deeper than 7,500 feet.

NIOC charts Qum area drilling time

By T. B. Young, Drilling Adviser
National Iranian Oil Company, Tehran

SEVERAL FACTORS are recognized as being common to drilling in central Iran. Lost circulation, salt formations and high pressure formations all influence drilling procedure. Drilling characteristics shown on the chart reflect procedures used in an interval from 2,600 feet to 7,800 feet.

In the top 2,600 feet, 2,000 feet of 12¼-inch hole can be drilled with three rock bits and reamed to 17½ inches with two rock bits. Fresh water mud, having a weight of 75 pounds per cubic foot and a viscosity of 45 seconds is suitable for drilling. The formation is red shale and clay with sand and silt stringers. The 13⅜-inch casing is cemented at 2,000 feet. Then 12¼-inch hole is drilled using two rock bits to 2,600 feet. During this drilling interval, the mud weight can be raised to 95 pounds per cubic foot.

In the interval shown, the mud weight is gradually increased to 100 pounds per cubic foot and the rotary table is held at a constant turning of 100 revolutions per minute. Increasing rotary speed above this does not affect penetration rate. The weight on the bit is 15,000 pounds at 2,600 feet and varied up to 37,000 pounds maximum to the depth of 7,002 feet. The penetration rate ranges from 3.07 feet per hour to 7.67 feet per hour.

From 2,608 feet to 7,002 feet requires 810.25 drilling hours. The number of 12¼-inch bits used is 38. This is an average of 115.6 feet per bit and an average bit penetration rate of 5.42 feet per hour.

Logging surveys are made, the hole is conditioned and then 9⅝-inch, P-110, 47-pound casing is set and cemented at 7,002 feet. Below this depth the hole is reduced to 8½ inches. The drilling mud is salt saturated and weight is built up to a maximum of 132 pounds per cubic foot while drilling below the 9⅝-inch casing shoe. The mud is maintained at about this weight until limestone is reached below 8,000 feet.

It is apparent that below 7,002 feet in the 8½-inch hole the penetration rate is decreased. The rotary table is slowed to 80 rpm maximum and weight on the bit is reduced so that the penetration rate will not exceed 5 feet per hour. This enables the driller and geologist to establish formation breaks along with the normal recording of the fact on the rig floor.

From 7,002 feet to 7,800 feet, eleven 8½-inch rock bits are required for an average of 72.5 feet per bit. Other characteristics do not reflect the true rate of drilling which could be done through this section because of the controlled conditions which are usually imposed.

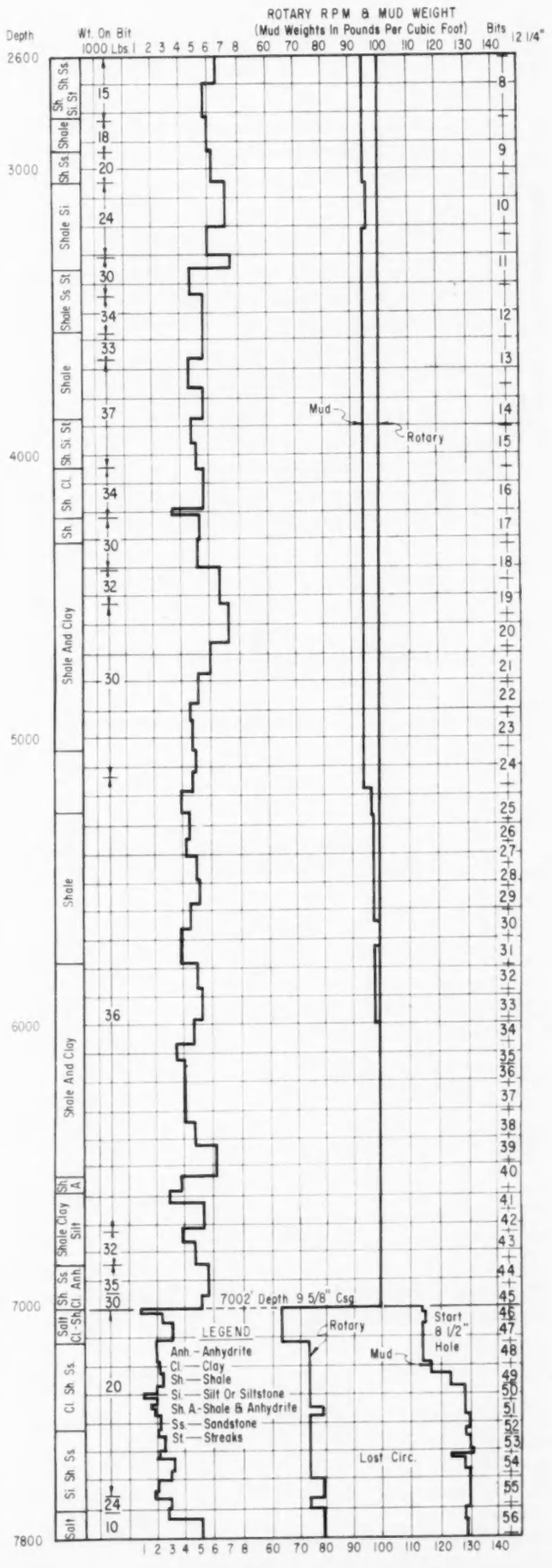
ACKNOWLEDGMENT

The author expresses his appreciation to the directors of the National Iranian Oil Company and to Messrs. Naficy and Farkhan of the Exploration and Production Division for permission to publish this article.

BIBLIOGRAPHY

Mostofi, B., and Frei, E., "The Main Sedimentary Basins of Iran and their Oil Possibilities," Fifth World Petroleum Congress, Section 1, Paper 17, 1959.

Kliewer, Don, "What's the Significance of Iranian Discovery?", WORLD OIL 143, No. 7, 206-207 (1956).



General Drilling Characteristics, Central Iran

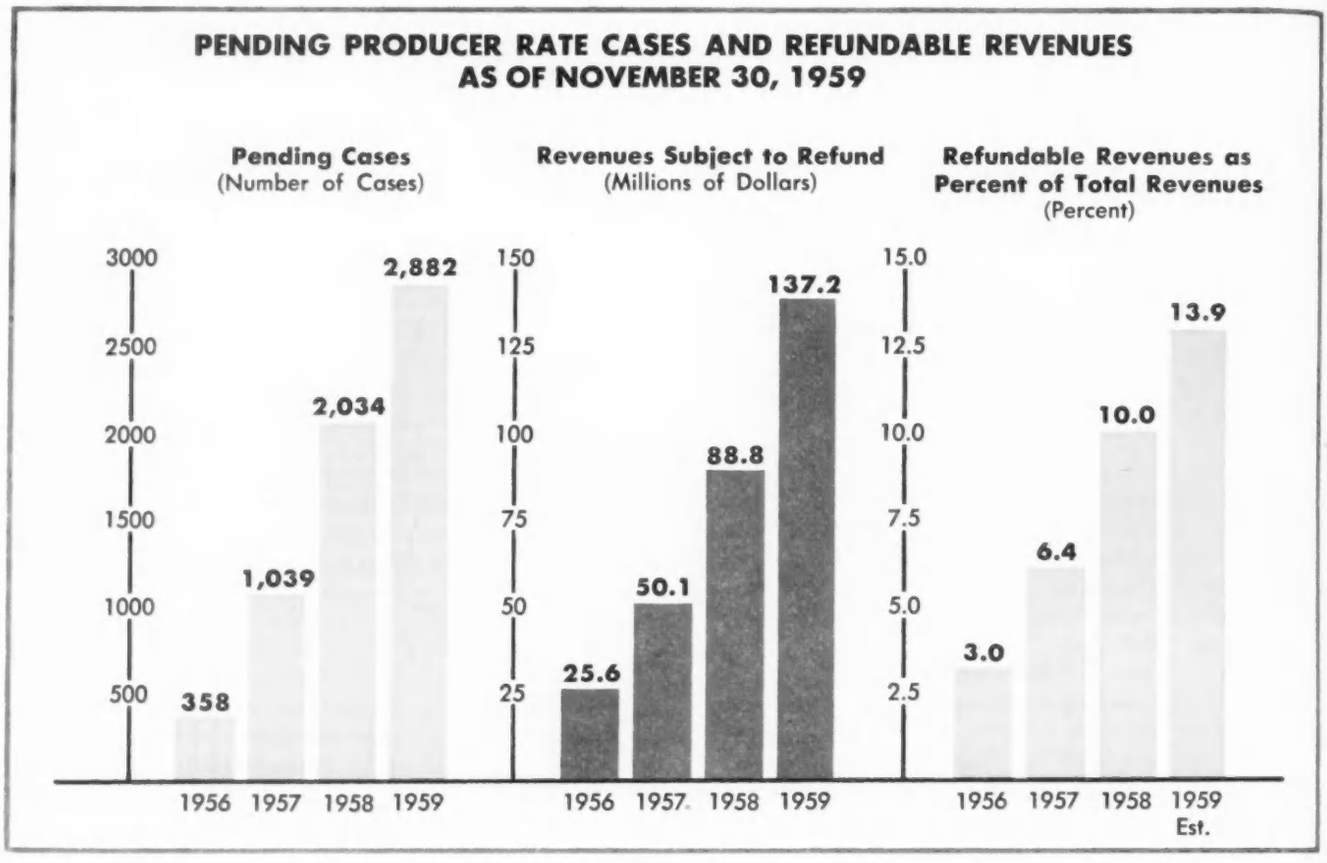


FIGURE 1

Natural gas in 1960...

Continued uncertainty over critical issues again will hinder growth of a vital industry

By Roger L. Conkling
Associate, H. Zinder and Associates, Inc.
Washington, D. C.

NATURAL GAS PRODUCTION—hardly worthy of being dignified as a separate business just two decades ago—is "big business" as the 1960s are ushered in.

On Wall Street, in thousands of industrial plants and millions of homes throughout the country, natural gas is in the blue-chip category. Realization of the far-reaching import of these blue chips is just beginning to sink in.

By and large, the cards have now been dealt. Each party at interest is playing its hand. The question for 1960 is how the cards will turn.

The real issue is supply. Will additional discoveries be sufficient to meet the ever increasing demands of gas-hungry consumers? Business investments totaling billions of dollars on one hand, and the character of the nation's energy picture on the other, ride on this issue. The answer hinges on how the many and vastly complicated facets of industry-government relationships are resolved. 1959 brought most of these issues into sharp focus.

A national fuels policy. One of the most critical and possibly damaging actions taken in 1959 was a coal-stimulated movement toward a national fuels policy, the setting of the nation's energy picture by government fiat rather than the market.

This being a political issue of first magnitude, little conclusive action by Congress is expected in 1960. But the debate will not be tabled, it will only be postponed. Hearings held by the Patman Subcommittee on Automation and Energy Resources of the Joint Economic Committee last fall touched on the peripheries of the problem.

Conservation: Inferior vs. superior uses. On the closely related subject of conservation, the Third Circuit Court in a November 3, 1959 decision reversed a Federal Power Commission refusal to certificate delivery by Transcontinental Gas Pipe Line Corporation of gas purchased in Texas by Consolidated Edison Company of New York for boiler fuel.[1]

"We think," said the Court, "that what the Commission has in effect done is to assert, by its examination and disapproval of the end use to be made of this gas, a general allocation

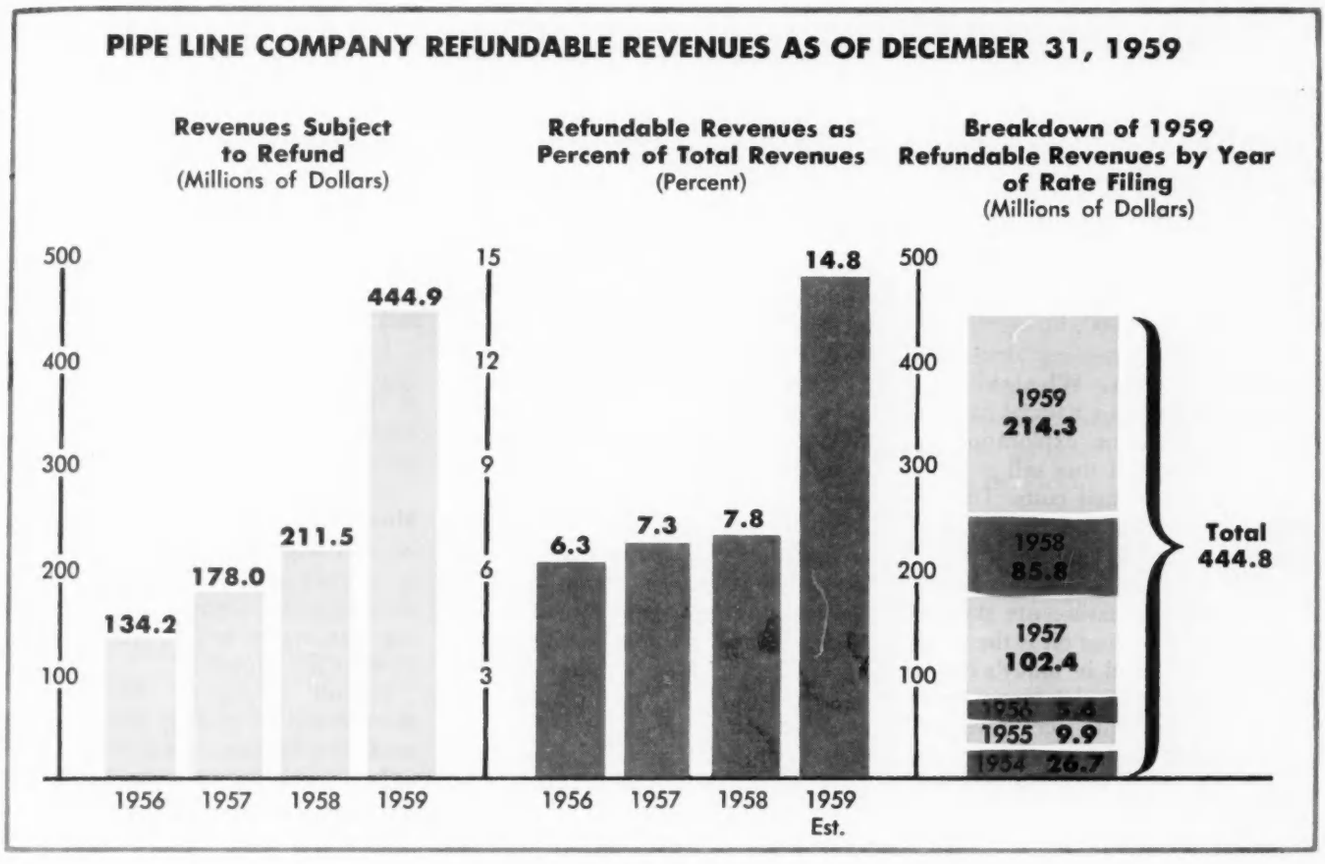


FIGURE 2

and conservation authority over the natural gas fields of the United States."

This is an authority, the Court found, which the Commission does not have this disposal of any inferior use argument as a basis for the rejection by FPC of proposed transmission by interstate pipe lines of gas for direct industrial uses (at least at the Circuit Court level), widens to the nation's boundaries the non-jurisdictional direct industrial market to gas.[2]

The decision is expected to be appealed by FPC to the U. S. Supreme Court.

Non-jurisdictional market. 1959 saw increasing awareness by producers of the tremendous non-jurisdictional outlet for their gas on their own doorsteps—the intrastate market.

Continental Oil and Pan American now have separate departments charged with developing this market. Humble has built a new 238-mile, 30-inch line from its King Ranch reserves into the Houston area. Monterey Oil formed a pipe line subsidiary to develop an intrastate market in Louisiana.

In 1960, the impact of non-jurisdictional marketing will begin to make itself felt upon long-line pipe lines and distributors in gas importing states. The already keen competition among producers and local pipe lines for non-jurisdictional markets will become keener.

New gas bill. Industry hopes for a non-utility type solution to regulation of its gas operations were stimulated from the doldrums on October 7, 1959 when Secretary of Interior Seaton issued a call for a new gas bill.

1960 will be a year of preparation for a new bill, but Congressional action is most unlikely in this election year. (See WORLD OIL editorial, January 1960.)

Canadian gas. Slow moving efforts to buy Canadian gas (principally by the Tennessee Gas Transmission, El Paso Natural Gas and Pacific Gas and Electric systems) may be successful in 1960.

In November 1959, Canada's National Energy Board was given export licensing authority. At the present time only Pacific Northwest Pipeline, purchasing from West Coast Transmission, brings major amounts of Canadian gas into the United States. The availability of Canadian gas (which can be exported only if it is found to be surplus to Canada's needs) could help to meet demands in the northern United States, but it is unlikely that this will result in any appreciable lessening of domestic production requirements.

Producer revenues under suspension. A staggering total of $137.2 millions per year of producer revenues, or about 14 percent of total annual revenues from pipe line sales, were subject to refund as of November 30, 1959 in 2,882 cases (Figure 1).

There seems little chance for a real breakthrough of the regulatory logjam in 1960. So the aggregate of producer revenues which may have to be refunded in whole or part will continue to climb. This means mounting pressure on producers to negotiate settlement of their rate cases, so that the multi-million dollar question marks on their balance sheets and income statements will be removed.

The entire industry, in fact, badly needs an end to the ever mounting millions of dollars in escrow. Pipe line company suspended revenues approximated $445 million per year, or

almost 15 percent of total annual revenues, as of the end of 1959 (Figure 2).

Dismissals. Throughout 1959, FPC made an attempt to clear a part of its backlog of rate cases by dismissing without hearings a number of cases where the prices were in line with those previously approved or with prevailing area prices.

It is probable that this attempt will be continued in 1960.

Producer costs. Whatever the method of regulation, natural gas producers can continue exploration for new reserves only if they sell at prices which will cover their costs. The importance of natural gas in the total petroleum revenue picture is slowly but surely making itself known.

Costs by any measure are skyrocketing. Gas rather than oil is the dominant product found in today's deeper wells. So gas must pick up a larger part of a larger bill. 1959 developed no clear understanding of these economic fundamentals. It is probably too much to hope for that 1960 will do appreciably better.

Costs will continue to climb in 1960 and, unless the regulatory climate for gas improves or the market outlook for oil becomes decidedly better, it will take a real effort to keep exploration and discoveries at the high levels of 1955-1958.

Utility-type (cost) regulation. The Phillips case moved slowly but inexorably forward in 1959. It now sits before the five-member Federal Power Commission. Other major producer rate cases also forged ahead.

Producers have consistently disputed cost as a method of regulation. But, due to the cost evidence submitted by the FPC staff and intervenors and their interpretation of *City of Detroit*, producers have uniformly felt compelled to introduce cost evidence in their cases.

FPC also faces a weighty legal problem in Phillips. It will have to decide whether a producer's contract rates can be raised when the cost determination shows that contract prices are not high enough to cover costs. This will involve a re-examination of the Mobile[3] and Memphis[4] doctrines.

Individual Rates: Contract, Uniform, or Cost-Based? The Phillips and other producer cases have explored in detail the ramifications of applying cost as a test of reasonableness of producers' rates as a whole. Little real attention has been given to how individual prices would be set or validated within the umbrella of approved over-all costs.

The question of whether producers' rates should conform to the contract, be uniform, or related to individual cost determinations, was joined only in the Tidewater Oil Company case in 1959. This may postpone a final FPC determination on individual prices beyond 1960, unless the Commission takes judicial notice of Tidewater (still in the hearing stage) in its verdict in Phillips.

Taxes under cost regulation. Events in 1959 confused rather than clarified the tax question. In its El Paso opinion[5] which is now being appealed, the Commission endorsed the principle that Congressionally awarded tax benefits to producers should not be denied through the regulatory process, but at the same time rolled in together taxes and rate of return for a total return on wellhead properties, including taxes, of 8.61 percent.

Meanwhile, its findings in the United Fuel case,[6] where a separate rate of return of 6¼ percent has already been established, and the only remaining issue is taxes, have been held up. No rolling in would seem possible in United Fuel.

The industry will await 1960 to see how this apparent conflict is resolved by the Commission, and thereafter by the Courts.

New sales. 1960 could see the development of some ground rules—at least at the Commission level—as to prices for new sales under certificate proceedings.

The United States Supreme Court's 1959 decisions in CATC[7] and Transco[8] demand a quick Commission answer. The CATC remand hearings are scheduled for early in the year.

Favored nations contract provisions. Flexible pricing provisions (favored nations particularly, and, indirectly, price redetermination) came under vigorous attack in 1959.[9]

These provisions have been the main instrumentality for raising producer prices to levels commensurate with current costs. The issue of the validity of these provisions in existing contracts and their future use in new contracts should be squarely before the Commission in 1960.

But the impact of the controversy is already being felt. The Commission has settled a number of pending cases on the basis that these provisions would be eliminated from future application.[10] Phillips Petroleum and El Paso have renegotiated their contracts to eliminate spiral escalation and favored nations clauses.

Intensified pressure to settle will lead to further rounds of negotiations in 1960, with the elimination or modification of flexible pricing provisions being an important bargaining point.

Slow progress ahead. The issues in which Congress is concerned probably will only simmer in 1960. But, although the Congressional Record may not report action, words will be tossed about aplenty.

Behind the scenes, the parties at interest will be girding themselves for a decisive battle in 1961.

It seems inevitable that the Federal Power Commission will take a stand during the year on the numerous questions pending before it. But many if not all of the Commission's decisions will be appealed to the Courts. Each appeal may entail two rounds of litigation, first to the Circuit and then the Supreme Court, which means time.

So 1960 will be a year of continued uncertainty as to the ground rules of regulation, with few permanent solutions.

Of the Federal Power Commission issues, decisions about cost are probably the most complex. Major disputes center on cost allocation methods—that is, the ways in which the huge body of joint costs are to be apportioned between oil and gas, and on the rate of return and taxes. Vastly different results occur as different choices are made on these scores.

The Commission has the full range to choose from in the Phillips record. (See the author's summary of Examiner Zwerdling's decision in Phillips case, WORLD OIL, June 1959.) One conclusion seems almost certain. Producers' costs, Phillips' included, arrived at on a reasonable allocation basis and applied company-wide, will be more than adequate to support current prices.

The cost-price squeeze (see WORLD OIL, November 1959) is increasingly making itself felt. This will compel

recognition in the gas regulatory process.

As difficult, though perhaps not as complex as cost, is the problem of new producer prices. In CATC, on June 22, 1959, the U. S. Supreme Court remanded back to the Commission for further review a certificated price of 21.4 cents per Mcf for offshore gas.

The Court declared, ". . . the initial certificating of a proposal under Sec. 7 (e) of the Act as being required by the public convenience and necessity becomes crucial." Initial prices require ". . . a most careful scrutiny and responsible reaction."

The Court noted that the Commission may "condition" certificates where the proposed price "is not in keeping with the public interest."

Perhaps with this implied suggestion in mind, on August 10, in the Transwestern case,[11] the Commission "price conditioned" a number of requested certificates, offering certificates only if the contract prices were reduced as follows:

AREA West Texas and Permian Basin (Texas and New Mexico)	Contract Price	Offered Certificate Price
Wellhead Sales	16.0¢ 19.5 21.8	16.0¢
Plant Sales	18.0 21.8	18.0
Puckett-Ellenburger (Treated for high carbon dioxide content)	12.0	11.0
Panhandle-Hugoton	23.0	17.0

Other producer sales have similarly been price conditioned.

On December 14, 1959, the Supreme Court, in the light of its earlier CATC decision, reversed the Third Circuit Court in the Transco case. The Circuit Court had found no grounds for overruling FPC's approval of the 22.4 to 23.3 cents per Mcf producer prices (including taxes) there involved.

Supply vs. price. However grave individual issues may be, the public interest centers on adequacy of supply. The end result of the regulatory process is price. Individually and collectively, producer prices must be such as to provide the incentive for exploration and development at a high level, to induce supplies sufficient to meet demands.

The inescapable increasing cost nature of petroleum production, the accentuation of increasing cost given by inflation, higher gas-oil ratios, the glut on the oil market which puts a stop to oil footing the gas bill, all point to the necessity for reasonable incentive prices.

Needed: More realistic cost allocations. The significance of the state of the oil market in relation to gas prices merits some elaboration. While gas regulation via the cost route purports to find a cost for gas and then to fix gas prices so as to be in line with this cost, the sales realization method of allocating joint costs which has been strenuously advocated by the FPC staff assumes, essentially, that gas should continue to bear the same share of joint oil-gas costs as it has in the past.

In a joint product situation, where the demand for one joint product is relatively stable (oil) and the demand for the other joint product is rising rapidly (gas), it is unrealistic to think that the entire expansion required by the growing demand can be financed at the expense of the stable product. If the gas market is to be served, expansion of gas discovery activities must be kept at high levels and this is more and more a function of the adequacy of gas prices.

YOU CAN ORDER YOUR EDITORIAL INDEX NOW

The annual WORLD OIL Editorial Index is now available. This convenient index, an annual service to WORLD OIL readers, will cover all issues published during 1959 and be bound in convenient pamphlet form. It will be sent FREE to all subscribers requesting copies.

To get your copy, address your order to: Librarian, Gulf Publishing Company, Post Office Box 2608, Houston 1, Texas. Or if you prefer, you can use the convenient Readers' Service Blue Postcard just inside the back cover of this and every issue of WORLD OIL. Just check the square indicated, fill in your name and address and drop the postpaid card in the mail. The annual WORLD OIL Editorial Index will be sent you by return mail. Do it now. The supply is limited.

On the other side of the price coin, and just as inescapable an economic fact, is that consumer-end competition from other fuels makes itself increasingly felt as gas prices rise. So competitive fuel prices in consumer markets sets an upper limit on producer prices. Within this limit the question is whether supply is to be artificially restricted below demand by too low producer prices.

A frequently overlooked aspect of the supply problem is its importance to the financial position and rates of pipe line companies. This aspect was recently pointed out to financial circles by Phillips Petroleum.

A large part of the bond indentures of pipe line companies provide for acceleration of the sinking fund payments if it is likely that the company will not have sufficient gas supplies for a full line load for the remaining period of the bond payment.

Any real uncertainty with respect to future supply caused by a slacking off of exploratory efforts of producers, could precipitate a major financial crisis for pipe lines and raise gas prices. This increase in pipe line prices, however, would not be associated with an increase in supply; rather it would reflect only a more rapid pipe line investment payout.

So supply is the real issue for 1960, on which all segments of the industry and regulatory authorities alike will—or should—concentrate.

LITERATURE CITED

[1] Consolidated Edison Company of New York, Inc. et al v. Federal Power Commission —— F. 2d. ——.

[2] In its Opinion No. 333 of November 27, 1959, the Commission refused to certificate a 100 million cubic feet per day boiler fuel sale by El Paso Natural Gas to Southern California Edison. FPC would make that volume of gas available for general use in California, to be allocated to Edison or others by local authorities as they saw fit.

[3] United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332.

[4] United Gas Pipeline Co. v. Memphis Light, Gas and Water Division, 358 U.S. 103.

[5] Opinion No. 326, In the *Matter of El Paso Natural Gas Company*. Docket No. G-4769, August 10, 1959.

[6] *In the Matter of United Fuel Gas Company*, Docket Nos. G-2451 and G-5475.

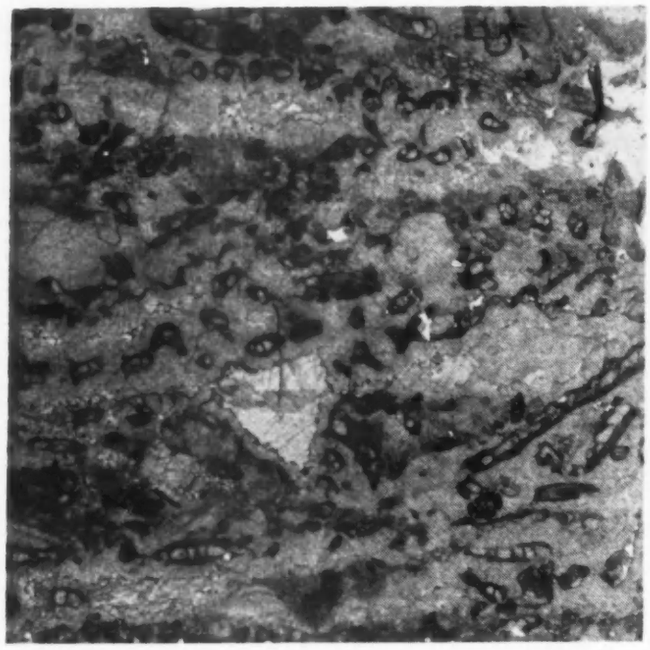
[7] Atlantic Refining Company, Cities Service Production Company, Continental Oil Company, et al, v. Public Service Commission of New York, et al, 79 S. Ct. 1246, 360 U.S. 378.

[8] Supreme Court's reversal of the Third Circuit Court on December 14, 1959. Writ of Certiorari granted. Decision Nos. 459, 473.

[9] In the Matter of Pure Oil Company, Docket No. 17930. Hearings were concluded on July 23, 1959. Examiner Law's decision on the issue has not yet been rendered.

[10] The 19 settlement orders covering 44 dockets in 1959, all involve Texas Eastern Transmission Corporation as purchaser. In each instance, favored nations and price redetermination clauses were eliminated and, in addition, the periods between fixed price escalations were lengthened.

[11] Opinion No. 328, in *Matters of Transwestern Pipeline Company*, Docket Nos. G-14871 et al, August 10, 1959.



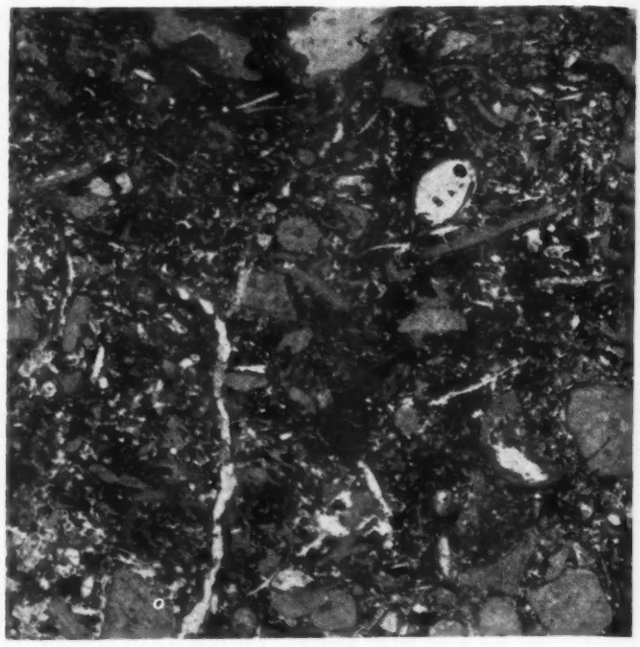


FIGURE 1—Photomicrographs show typical core lithology of bioherms in the Williston Basin subsurface. Magnitude of from 500 to 600 feet have been indicated by wells drilled on the edges of such bioherm cores. Original interstices are apt to be heavily cemented with calcite, which may comprise more than two-thirds of the core facies volume.

How to analyze bioherms in the Williston Basin

Lagoonal, core, marine facies crucial in Mission Canyon oil search; seismic data desired

By Paul J. Lewis, President
Northwest Geological Service
Billings, Montana

SINCE BIOHERM FACIES have been established as producing reservoirs in the Williston Basin, a better understanding of the variations of biohermal development will aid the search for this type of reservoir. Definition of bioherms and their facies in the Mission Canyon formation reveals the origin of certain reservoirs and provides the necessary criteria to seek other reservoirs of this type.

The author believes that the Norby pay of the Antelope field, McKenzie County, North Dakota, and the Fast zone of Roosevelt County, Montana, are facies of bioherms. Numerous wildcats have penetrated recognizable biohermal facies with oil shows. In some cases, a higher structural position on the reservoir may be obtained by applying principles of sedimentation peculiar to bioherms.

Since Mississippian rocks do not outcrop within the limits of the Williston Basin, bioherm characteristics from other areas of surface exposures are applied to the subsurface of the Williston Basin. Laudon and Bowsher[1] made an extensive analysis and description of the Alamagordo bioherms of New Mexico. Parkinson[2] summarized much of the previous work and the theory of sedimentation of the reef-knolls of northern England. Pray[3] discussed the bryozoan core facies of the Mississippian bioherms of the southern United States. His analysis and photomicrographs of the core rock assist greatly in recognition of this facies in subsurface rocks. Harbaugh[4] described the bioherms occurring in surface outcrops of the Boone formation of Oklahoma.

Bioherm—reef distinction. In exploring for reservoirs in bioherms, recognition of the finer differences between bioherms and reefs becomes important. True reefs are biotic assemblages which form a wave-resistant structure and are capable of growth into the zone of more violent wave agitation.

Although the bioherms show evidence of a degree of agitation, configuration and character of fragments which compose the flank facies indicate that bioherms did not develop upward into the most vigorously agitated levels. The dominant bryozoan fauna in the core rock throws ques-

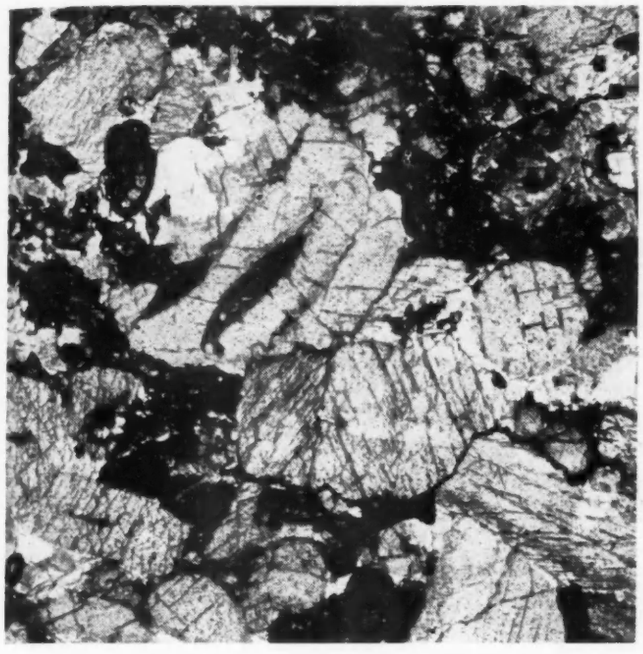


FIGURE 2—Photomicrographs of bioherm flank facies show crinoid-bryozoan calcirudite and calcernite (left); and less porous crinoid calcarenite (right). Such facies provide Mission Canyon reservoirs, interfingering with core margins. More "clastic" type environment creates coarse texture and primary porosity. Lagoonal lime mud mingles with this facies.

tion on the ability of this fauna to withstand the most vigorous levels. Although algae are suspected to be in the core rock, their presence has not been positively established. The predominance of aphanitic calcite in the core rock indicates the deposition of primary lime muds during core growth, creating a dense rock without porosity and permeability.

Core facies. The core facies develops in a mound shape with quaquaversal dips. According to the literature the vertical height may range from a few feet to as much as 1,500 feet. A number of bioherms from 200 to 350 feet have been noted in various areas. They range from a few feet to 3½ miles in diameter. Although a well drilled continuously in the core facies has not been analyzed, those wells that have penetrated the edges of the core and the flank facies indicate cores of 500 to 600 feet magnitude in the Williston Basin (Figure 1).

In Pray's detailed analysis of core rock of bioherms of the Southwestern United States,[3] various significant facts appear applicable to the subsurface bioherms of the Williston Basin. The core rock is a massive, dark colored, relatively nonfossiliferous calcilutite. Thin-section examination reveals the fenestrate bryozoans to be the dominant fauna. Crinoid fragments, because they are easily recognized are the most obvious organism (but they are few). In addition, other types of bryozoans, cephalopods, corals, brachiopods and ostracods are occasionally noted.

Calcite in interstices. More than two-thirds of the core facies volume is composed of aphanitic calcite and coarsely crystalline calcite, with aphanitic calcite predominating. Pray assumes that the aphanitic calcite represents primary lime muds which were deposited at time of deposition. Coarsely crystalline calcite indicates the infilling of primary voids and local recrystallization of lime muds. The flank facies, which is believed to have had primary interstitial porosity is infilled by coarsely crystalline calcite in varying amounts.

Porous flank facies. The flank facies of the bioherms are economically the important part since they form the reservoirs. Interfingering with the core margins are two readily recognized lithologic types. The crinoid-bryozoan calcirudite and calcarenite is composed of coarse to fine, fragmented crinoid and bryozoan fragments. Although fragmentation predominates, a high degree of abrasion is not evident on individual particles. This indicates the organisms were fragmented and sorted by agitated water but were not abraded in the highly agitated zones. The "clastic" environment creates the coarse texture resulting in primary reservoir porosity (Figure 2).

Crinoidal calcarenite. Another flank facies is the crinoidal calcarenite composed of finer fragments of crinoids. This facies has a fragment size gradational to the crinoid-bryozoan facies. All variations in fragment size between the two should be anticipated. Less porosity is developed in the crinoid calcarenite, as some of the lime mud found in the lagoonal area mingles with this facies.

Host rock. The host rock enclosing the bioherms consists of an argillaceous, siliceous, finely fossiliferous limestone. In the central portion of the Williston Basin this type is the

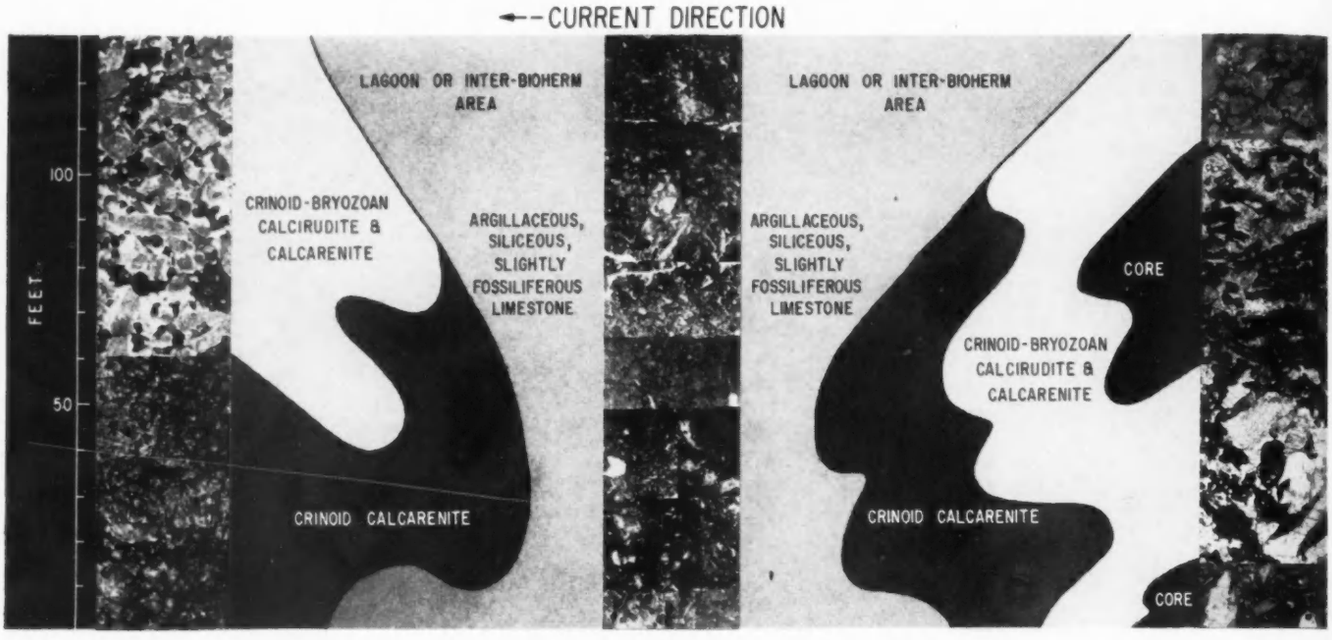


FIGURE 3—Photomicrographs showing 130 feet of Mission Canyon bioherm section indicate facies changes over a 20-mile area. Crinoid-bryozoan calcirudite and calcarenite facies interfingers with crinoidal calcarenite and core facies. Host rock (center) predominates and encloses bioherms. Location of flank facies on lagoonal side of bioherm cores is important.

predominant lithology of the Mission Canyon formation. It lacks porosity or permeability except when fractured and thus is not a natural reservoir rock. The host rock is an ideal *source* rock and shows much oil staining through hundreds of feet. With biohermal reservoirs enclosed in the dense source rock, ideal conditions exist for the accumulation and entrapment of hydrocarbons.

Although the core rock lacks porosity and permeabiilty and is not the facies desired, it is important to locate the core since development of the other facies are related to it. Due to similarity of the lithology of the core and the host rock on cursory examination, thin sectioning is recommended for positive identification (Figure 3).

The potential reservoirs are the flank facies of the crinoid-bryozoan calcirudites and calcarenites. These facies have a thicker development on the lagoonal than on the margin side. Thus, a higher structural position could be obtained on the porous zones by locating a well on the lagoonal side. Since the flank facies encircle the core, the resultant reservoir above an oil-water contact would be, in plan view, crescent in shape with the diameter of the core being the radius of the inner arc. In a typical case, several wells have penetrated the lower marine side of the flank facies and recovered water on test, although some oil staining was present.

Seismic analysis? Recognition of certain of the facies by seismic methods appears possible. Some analysis has been made but a lack of access to records over suspected areas of development has hampered it.

Promising avenues are the density differences and the massive-versus-bedded characteristics of the various facies. Structural anomalies at depths other than the Mission Canyon may be due to velocity variations induced by the bioherms within the Mission Canyon. Variations in record character of the Mission Canyon interval have been noted. Record quality on selected shot points does not appear to be a plausible explanation, as the records present very close comparison in the sections above and below the anomalous interval. The geophysicist and stratigrapher should work closely in order to interpret the seismic data accurately as it might relate to biohermal development.

About the Author

Paul J. Lewis was born in Oklahoma and lived in Newark, Ohio, during most of his youth before receiving his B.A. degree in geology from Denison University in 1946. The following year Lewis acquired his M.A. degree in geology from the University of Kansas. From 1947 to 1951, he worked for The California Company in Oklahoma, Virginia and Montana. Since 1951, he has worked on the stratigraphy of the Williston Basin and other areas in Montana. He is president of Northwest Geological Service.

LITERATURE CITED

[1] Laudon, L. R. and Bowsher, A. L., "Mississippian Formations of Sacramento Mountains, New Mexico, AAPG *Bulletin*, 25, pp. 2107-2160 (1941).

[2] Parkinson, D., "Lower Carboniferous Reefs of Northern England," AAPG *Bulletin* 41, No. 3, pp. 511-537 (1957).

[3] Pray, L. C., "Fenestrate Bryozoan Core Facies, Mississippian Bioherms, Southwestern United States" *Journal of Sedimentary Petrology* 28, pp. 261-273 (1958).

[4] Harbaugh, J. W., "Mississippian Bioherms in Northeast Oklahoma," AAPG *Bulletin* 41, No. 11, pp. 2530-2544 (1957).

In New Mexico . . .

Standard rig used to drill 46-inch holes

Target of this California contractor is 60-inch holes to 4,000-foot depths

By Gilbert M. Wilson
Western District Editor, WORLD OIL

INTERESTING MODIFICATIONS of existing rig tools and techniques, together with outright designing and fabrication of hitherto non-existent casing handling equipment, were involved in a recent 46-inch diameter hole contract completed late last year by Terminal Drilling and Production Company, Wilmington, Calif.

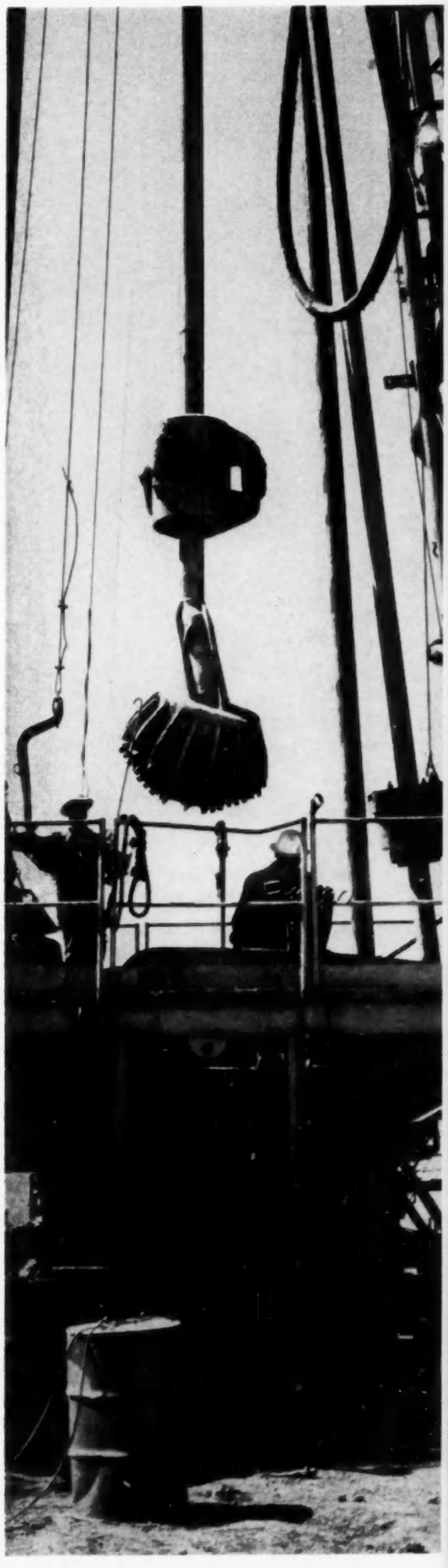
Already familiar with the problems of drilling large diameter holes using king-size tools and somewhat modified techniques, Terminal was called upon by Phillips Petroleum Company to drill, and case with 36-inch casing, two 46-inch holes to depths of 930 and 1,432 feet, respectively, in the company's uranium mining operations in the Ambrosia Lake Mining District near Grants, N. M. The holes were designed to serve as ventilation shafts and, if necessary, as escape hatches, in the deep mining operations. In recent years, Terminal has drilled numerous bell holes having diameters up to 36 inches, to depths of from 200 to 250 feet in the Wilmington field; these holes being a part of the program to protect well casing from shearing during earth slippages or earthquakes. More recently, at the Atomic Energy Commission's Nevada testing grounds, in connection with the underground explosions recently conducted there, Terminal drilled, and cased with 36-inch casing, three 500-foot holes.

Formations to be drilled at the Grants site were not unlike marine formations encountered in typical oil field operations. The top 100 feet consisted primarily of loose sand; was followed by 1,060 feet of Mancos shale containing occasional hard sand streaks; about 75 feet of hard Dakota sandstone; 160 feet of Brushy Basin shale; and 35 feet of Westwater sandstone, the latter being the formation bearing the uranium values.

Holes drilled, reamed, in stages. The holes were drilled and opened in stages. Using the second hole, deeper of the two, as the example, a 20-foot conductor pipe, 48 inches in diameter, was set in a hole that was dug by a crane bucket, then cemented to the surface. A 15-inch pilot hole was drilled to 1462 feet; this being followed by the second stage, a 26-inch hole to 1,450 feet. The third stage, 36-inch hole, was carried to 1,430 feet; and the final, 46-inch hole, was drilled to 1,421 feet. This was followed by an offset type bit and reamer combination, a "stiff" combination, that assured complete removal of shoulders or short dog legs that might interfere with running of the casing.

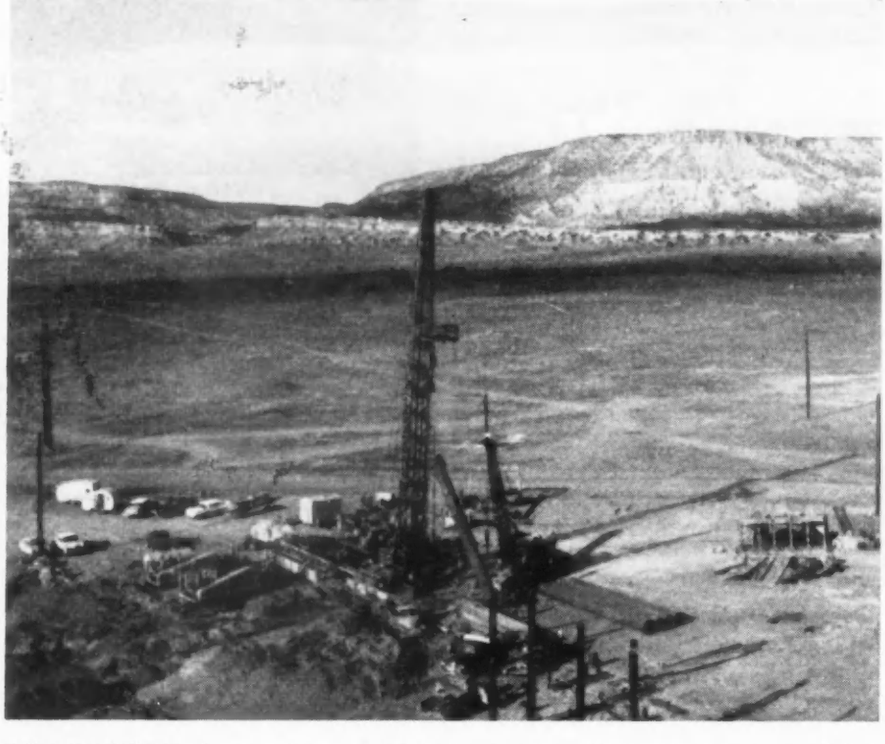
The drill string employed was 5 9/16-inch drill pipe with three 8-inch by 40-foot drill collars. Pump equipment consisted of two diesel driven 7¼ x 14 pumps arranged in parallel to give a total of about 500 hydraulic horsepower.

Other drilling equipment was conventional, consisting of a trailer-



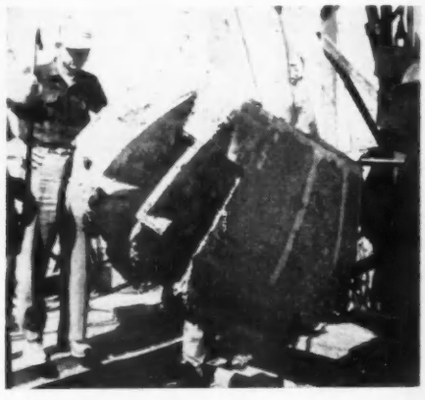
GOING INTO THE HOLE. The 46-inch bit and reamer are run in to ream hole before running 36-inch casing.

IMMENSITY OF BIT and reamer is shown here before tools were shipped to New Mexico drilling site where two wells, one to 930 feet and the other 1,432 feet, were drilled and cased.



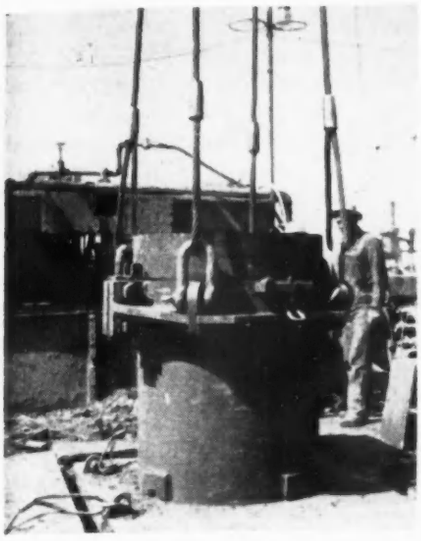
ON LOCATION, just as joint of 36-inch pipe is pulled preparatory to being welded and run in hole.

EASIER HANDLING of tool joints at derrick floor level was possible with this specially designed box, inserted through mud-tight door to provide support inside the 48-inch riser for the long bits and reamers. Joint of tubing, which facilitates insertion of the box, also is counterbalance.



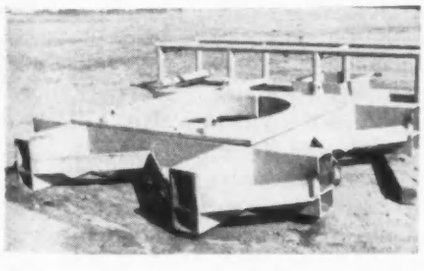
BALLING OF BITS, particularly in shale formations, required round-tripping to clean cutters. Modification of mud ports and lengthening and redirecting nozzles helped to minimize problem.

WITH 5 9/16-INCH being laid down, contractor prepares to remove sub-base, install spider and run casing. Huge shoe, welded to first joint of 1-inch wall 36-inch pipe is visible in left foreground.



ELEVATORS of special design, comprising two half-sections bolted together around the pipe, were designed to support with ample safety factor the more than 453,000 pounds total weight of casing, shoe and slip collars run in the 1,432-foot hole. Note heavy steel lugs welded to pipe on which string rests while in slips.

36-INCH CENTRALIZER being installed after weld was completed. On the deeper hole, eight such centralizers were run, one about every 200 feet.



SPECIALLY DESIGNED, reinforced casing spider and slips simplified running of 36-inch casing string.

mounted portable, 96-foot mast-type diesel rig capable of drilling to 5000 feet with 4½-inch drill pipe. The rig had an 8-foot, 6-inch sub-structure slightly modified to accommodate the large hole conditions; an 80-barrel shaker tank and a 120-barrel suction tank.

Bit support inside conductor pipe. An unusual feature of the equipment, one that was devised by Terminal to facilitate handling of the king-size bits and reamers, was a device for supporting the bit in the conductor pipe below the derrick floor and at a level that permitted easier handling of the tool joints. It consisted of a special shelf-like steel box that was inserted through a mud-tight door in the 48-inch riser at a point some two or three feet above ground level. Designed and fabricated in Terminal's yard, as were all of the other modifications involved, the rectangular box was about 1½ feet wide by 4½ feet long, and was extended through the riser to a boxed-in shelf welded in the opposite side of the 48-inch pipe. It was inserted with the aid of a joint of 2½-inch tubing coupled to it with a hammer type union, the tubing serving also as a counterbalance when the unit was picked up with the sand line. When the bit again was ready to be re-run, the box was withdrawn and the mud-tight door re-installed and bolted.

Mud conditioning important. Drilling operations, in most respects were normal. Mud viscosity had to be watched carefully as some trouble was experienced in lifting cuttings due to the much larger diameter of the hole and resultant lower velocity of the mud. At some points the bit would bounce on the cuttings and, in a particular chert nodule bed in the Mancos shale section, the drill pipe sometimes torqued up badly. The two mud pumps were able to maintain a circulation rate, in the 46-inch hole, of approximately 1,100 gallons per minute, giving an annular velocity of about 13 feet per minute. Cuttings in the 46-inch hole averaged ¼-inch in diameter or smaller when drilling in shale, and considerably finer than that when in sandstone. Balling of the bits was experienced frequently while drilling in shale formations, requiring round-tripping in order to clean the cutters. However, this tendency to ball up was reduced by alteration of the circulation ports on the 36- and 46-inch hole enlargers. Ports were made smaller and nozzles longer, than re-directed to jet mud across the cutters for a better cleaning action.

Conventional gel and clay mud was used, a typical specification being a weight of 78 pounds per cubic foot; viscosity of 50 seconds; water loss of 9.0 cc; and a sand content of 3½ percent.

The following operating techniques and hole condition, while more or less typical of both holes, are based on records taken in drilling of the deeper, 1,432-foot hole:

Troublesome water flows that were encountered in a nearbly hand-dug shaft at several points easily were mudded off and gave no trouble in the rotary-drilled hole. It was in this respect that the oilfield drilling rig proved, among other points, that it was superior for this type of work when compared with conventional mining techniques involved in digging a shaft. In a nearby shaft, dug by conventional methods, water flows brought work almost to a stop even with the aid of large de-watering pumps. In fact, in the time required to drill the two rotary-drilled shafts, the hand-dug shaft was able to make little progress.

Lost circulation trouble was experienced for a short while in the sandy surface formation below the conductor pipe shoe and in the Dakota sandstone at around 1,300 feet. Lost circulation materials, comprising for the most part cement and fiber, were succesfully used in combatting fluid loss.

Penetration rates for the several bit sizes (based on 24-hour day) were as follows:

Bit Size	Average Penetration Rate (Feet Per Day)
15-inch	159
26 "	98
36 "	83
46 "	79

On the deeper hole, time elapsed was 64 days from spud to completion. This included one day combatting lost circulation, seven days fishing and two days running casing. The fishing job, incidentally, was the only one encountered in the drilling of the two holes, and it involved the loss of the 15-inch pilot bit that unscrewed from the bottom of the 26-inch hole opener. The pilot bit could not be fished out so an attempt was made to break it up with a down-hole directional

charge, then recover the fragments with a magnet. However, no fragments were recovered after the shot. The bit could not be felt in subsequent drilling and it was pushed on down into the "sump," or original bottom of the first pilot hole.

No crooked hole problems were encountered. A single shot survey was run at 60-foot intervals in the 15-inch pilot hole to make sure this first run to total depth would be vertical and, since a pilot hole was run ahead of each successively larger hole-opener bit, the final hole was in good condition except for minor shoulders that were reamed just before pipe was run. That the 36-inch casing, a "rigid" string with little ability to bend as would normal, lighter-walled, oil well casing, went to bottom without difficulty, attests to the good condition of the hole.

Tapered wall casing string. The 36-inch string was a tapered wall casing which, on the deeper of the two holes, called for the following wall thicknesses and weights per foot:

Length	Wall Thickness	Pounds Per Foot
240 Feet	⅝-Inch	236.18
360 "	¾-Inch	282.42
340 "	⅞-Inch	328.30
480 "	1-Inch	373.00
6 "	(Shoe & Extension)	
1,426 Feet		

Total weight of the string, including shoe and slip joint collars, amounted to 453,700 pounds, lighter by only some 26,000 pounds, than a combination 7⅝-inch and 7-inch casing string that recently was run in a 23,000-foot well in West Texas.

A 36-inch double-ball float shoe similar to a conventional shoe, was run on the bottom of the string. Casing, with the 1-inch wall pipe on bottom, was run in 40-foot length joints. They were equipped with heavy slip collars which permitted making a slip joint and fillet weld to give additional strength. Seven passes were required in welding the 1-inch wall and correspondingly fewer on lighter wall sections up the hole.

Unusual casing handling equipment. Running the casing, removing mud from the completed hole and other completion details involved some of the more interesting aspects of the large-hole operation. After the hole was opened to full 46 inches and the drill pipe laid down, the sub-base removed, the 48-inch riser cut off level with the mat and the specially-made casing spider, designed and fabricated in Terminal's yard, placed over the hole. The spider support consisted of a rectangular, re-inforced structure in which the 36-inch casing slips were placed. The lips were two half-circle sections set in the square box provided in the spider. They were designed to catch the casing on four equally-spaced lugs previously welded to each joint some four feet below the slip collar.

To stabilize 2½-inch tubing when mud was being swabbed from one of the cased holes, these specially designed centralizers made of sucker rod material and installed on pup joints, were positioned at intervals in the tubing string.

The 36-inch shoe already welded to the first joint, was picked up, set in the slips and the second joint welded to it. The string was floated down with just enough mud inside it to cause the pipe to move down slowly. Casing centralizers were run in at intervals, eight being used on the deeper hole string; six on the shallower hole string.

On completion of each weld, the string was picked up with the specially-designed clamp-on type elevators, the slips removed with the cat line and the casing lowered. The slips then were re-installed to catch the pipe at the next set of lugs. The casing clamp was removed and placed on the next joint.

When the casing was landed on bottom, the string was filled with mud. The cementing operation, with circulation brought to the surface, involved a somewhat unusual technique. Drill pipe was run in with open end being placed about three feet above the shoe. To assure equalized pressures inside and outside the casing, a pressure plate of 1-inch steel was welded over the top of the casing, enclosing the drill pipe also. This plate prevented mud from escaping when cement was put away.

Four cement trucks were employed. Some 4,500 sacks of slow-cementing Portland cement to which was added 254 sacks of high strength gel and 1125 pounds of cellulose film flake, the latter as an anti-lost circulation additive, were pumped through the drill pipe. The cementing operation required an hour and 20 minutes.

Mud swabbed through tubing. Somewhat unusual procedures were employed, also, in removing mud from the cased hole. In both holes, a string of 2½-inch tubing was run and the mud swabbed through it. In the shallower hole, four specially-designed centralizers made of sucker rod material (see photo at left) were run in on the tubing string to prevent buckling or lashing when the swab was pulled. A bailer was run, after tubing was removed, to clean out mud that could not be swabbed.

In the second hole, centralizers were not used. Instead, the tubing was run inside the drill pipe and swabbing done through it as on the first hole. In order to still further speed up the swabbing, a valve was welded into the pressure plate (previously described) and, using the rig compressor, the annular space between casing and drill pipe was pressured with air. This "air-lifting," with about 90 pound per square inch maintained on the annulus, helped to lift and flow the mud as swabbing continued. As in the first hole, a bailer was used to finish off the bottom. The shoe was not drilled out in either of the two holes.

Many large-hole jobs of this kind, Terminal Drilling believes, can be handled using standard oilfield tools and practices. Modifications and improvements of course will be made and, as has been true in the history of the oil industry, costs and drilling time ultimately will be reduced as techniques improve. As evidence of this, Terminal now is designing equipment and techniques that will make possible the drilling of 60-inch holes to 4,000 feet. These holes will not only be used in mining and related operations, but such currently-discussed oil industry projects as the use of nuclear explosive for the recovery of oil from the Athabaska tar sands and shale oil deposits. —**The End**

For Your PRODUCTION File

Here's how to improve your gas lift installations

PART 7: How to select surface controller pilots for special gas lift applications

By H. W. Winkler, Engineer
Camco, Incorporated, Houston

In some gas lift installations, the difference between satisfactory and unsatisfactory operation is dependent upon the type of surface equipment used to control injection gas. Other installations cannot be operated at all without proper control of the injection gas. There are many types of time cycle, pressure control and combination time cycle pressure control pilots which can be used to operate the motor valve on the injection gas line. This article will recommend and describe surface injection gas control equipment for several types of gas lift installations.

Pilot with tubing pressure cutoff. A tubing pressure cutoff is recommended for gas lift wells that have a tendency to flow. When the well begins to flow, tubing pressure increases. The tubing pressure control is adjusted to shut the surface controller on the injection gas line when tubing pressure reaches a pre-set value. Injection gas cannot enter the casing until the well ceases to flow and tubing pressure decreases. A typical wellhead hookup for a surface controller with a tubing cutoff is similar to Figure 17 except no casing pressure control line is required.

Time opening, pressure closing pilot for intermittent lift. This type pilot can be used to advantage on most intermittent installations. It is desirable particularly for wells which have a varying injection gas line pressure.

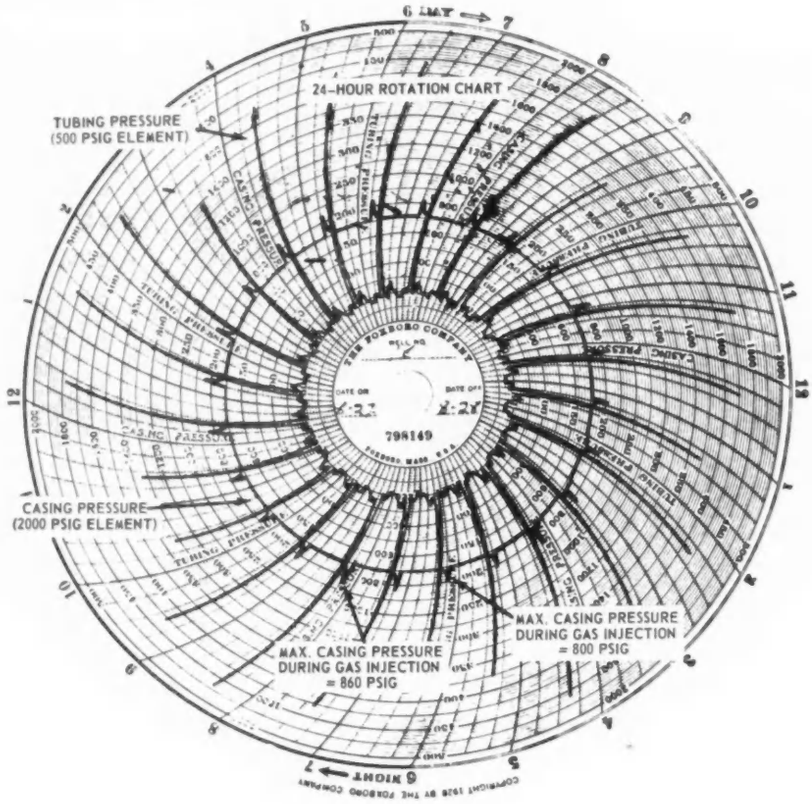
If line pressure varies significantly, the duration of the gas injection per cycle must be adjusted for minimum line pressure to assure opening of the operating gas lift valve during every cycle. Therefore, too much gas is used per cycle at all line pressures above minimum line pressure.

If the duration of gas injection is based on an average line pressure, the operating intermitting valve will not open during an injection gas cycle when line pressure is low. Pressure recorder charts obtained from wells with a varying line pressure are shown in Figure 14.

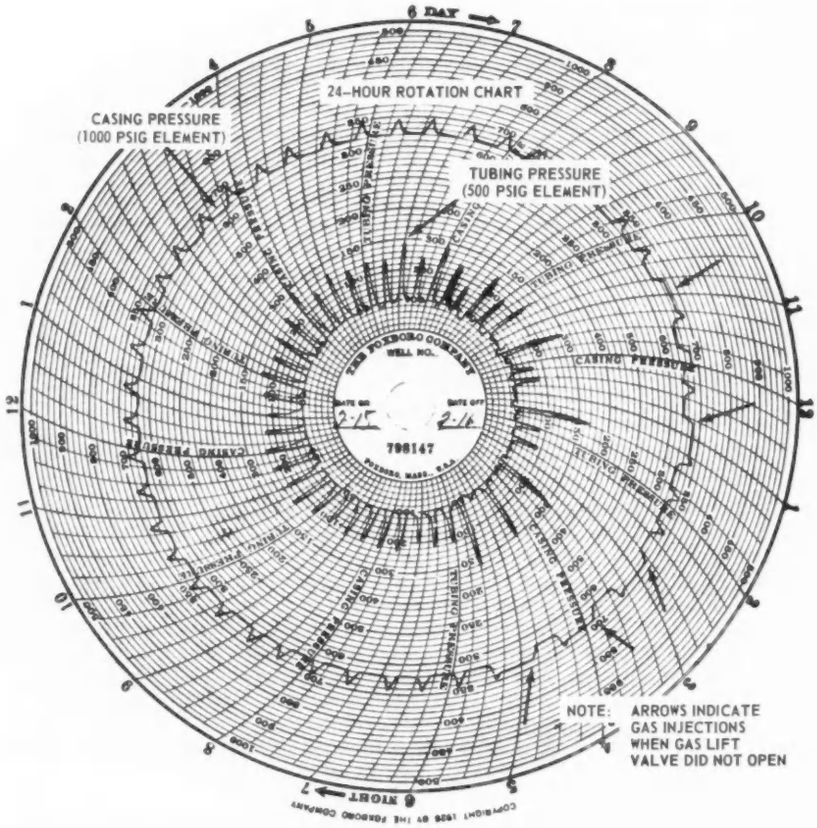
In Figure 14-A gas injection duration was adjusted for minimum line pressure. The increase in casing pressure for the same duration of gas injection varied as much as 60 psi for different cycles. Casing pressure increased to 800 psig during the 6:15 p.m. injection cycle, and during the 8:15 p.m. injection cycle, only two hours later, increased to 860 psig. These differences in pressure build-up also are indicated by the tubing pressure recording.

The volume of injection gas used during each of these cycles can be estimated from Figure 8 (World Oil, Page 108, December 1959). This well was equipped with 2-inch tubing and 5½-inch O.D. casing and the operating valve was at a depth of 6,200 feet. The approximate volume of gas (at 14.65 psia and 60° F) used during the 6:15 p.m. cycle was 4,030 cubic feet and during the 8:15 p.m. cycle, 6,760 cubic feet. Thus, a difference of over 2,700 cubic feet of injection gas per cycle was used for the same duration of gas injection due to a variation in line pressure.

The chart shown in Figure 14-B was obtained from a well in which the duration of gas injection was not based on minimum line pressure. The operating intermittent gas lift valve did not open during the injection gas cycles



(A) Difference in casing pressure build-up during equal periods of gas injection varies 60 psi due to variation in injection gas line pressure.



(B) Duration of gas injection was not based on minimum injection gas line pressure. Operating gas lift valve did not open during injection cycle when line pressure was low.

FIGURE 14: Two-pen pressure recorder charts from intermittent gas lift wells with varying injection gas line pressure.

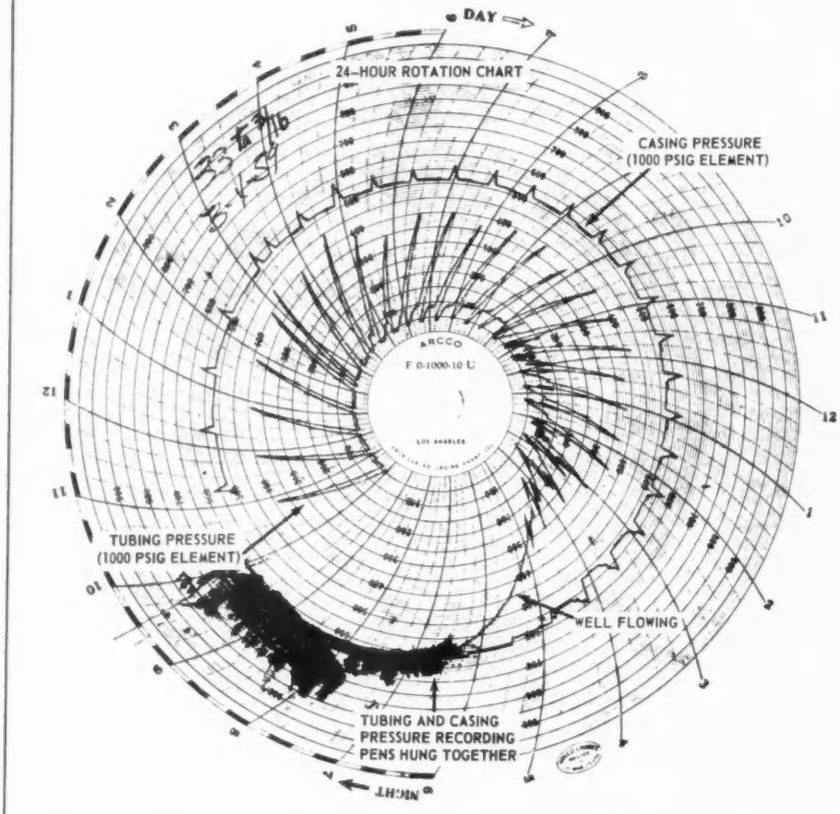


FIGURE 15: Two-pen pressure recorder chart obtained from intermittent gas lift well which flows periodically.

when the line pressure was low. As can be noted from the chart, the operating valve did not open during several gas injection cycles between 10:30 a.m. and 5:30 p.m.

The time opening-pressure closing pilot would have been ideally suited for both cases in Figure 14. The pilot is adjusted for an excessive period of gas injection and closes after a set built-up in casing pressure is reached, regardless of the time required for the increase. The number of injection gas cycles per day is controlled by the timing portion of the pilot and the volume of injection gas per cycle is governed by the casing pressure control. The surface controller hook-up is similar to Figure 17 except no tubing pressure control line is required.

Time cycle pilot with tubing pressure control of motor valve on flow line of intermittent wells which flow periodically. Some intermittent gas lift wells will flow occasionally and must be produced with a choke in the flow line to prevent overloading producing facilities at the tank battery. Restrictions in wellheads and flow lines should be avoided to minimize fall-back and decrease gas requirements. The two-pen pressure recorder chart in Figure 15 was obtained from an intermittent well which flows periodically. This well was produced efficiently with the hook-up shown in Figure 16.

The tubing pressure element on the pilot has priority over the time cycle control. When tubing pressure increases to a set value, the motor valve on the flow line and the controller on the injection gas line close. Thus, the well is switched through the small choke in the bypass until flow ceases and tubing pressure decreases.

A large stem and seat assembly is used in the motor valve on the flow line. When the motor valve is open the well produces through both the large inner valve assembly and the small choke in the bypass. The tubing recording between 11:00 p.m. and 4:00 a.m. indicates no excessive back pressure during normal intermittent operation. The tubing pressure decreased sharply after each slug surfaced.

Combination tubing-casing pressure control pilot for fluid operated installations. Some fluid operated installations require a decrease in casing pressure before the gas lift valves will close. A significant decrease in casing pressure occurred in the fluid operated installation illustrated by the pressure recorder chart in Figure 10 (WORLD OIL,

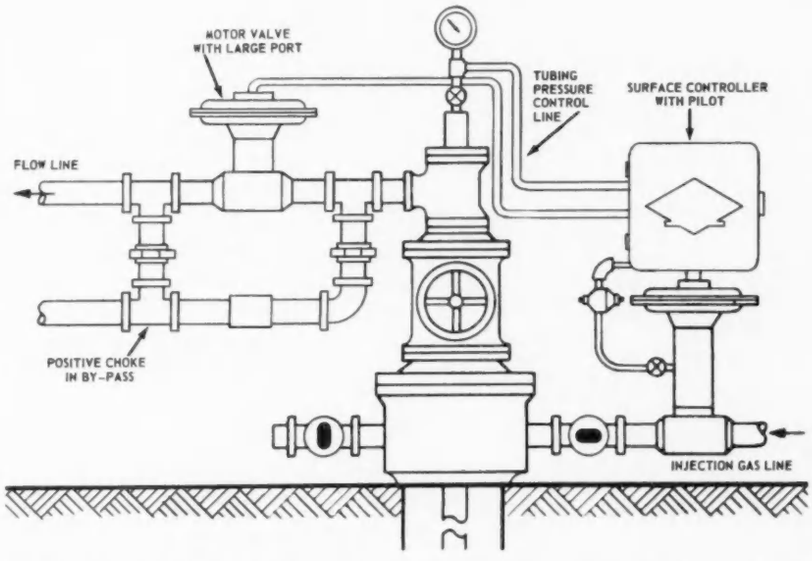


FIGURE 16: Wellhead hook-up using time cycle pilot with tubing pressure control for surface controller on injection gas line of intermittent gas lift well which will flow periodically. When well begins to flow, tubing pressure control closes motor valve on flow line and well produces through small choke in bypass.

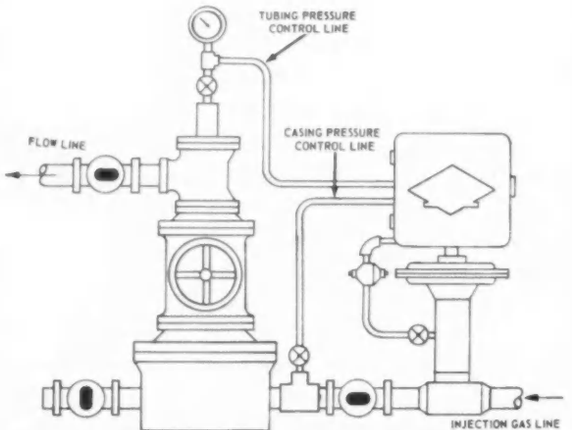


FIGURE 17: Wellhead hook-up for fluid operated gas lift installation using combination tubing and casing pressure control pilot for surface controller on injection gas line.

Page 110, December 1959). A small choke was used in the injection gas line of this well to effect the necessary decrease in casing pressure. Use of the small choke was feasible in this case since the producing rate was low; however, if a well must be lifted near maximum cycle frequency, the choke cannot be used.

A tubing-casing pressure control pilot is recommended for a fluid operated installation which must be produced near maximum cycle frequency. The tubing pressure control is used as a tubing cutoff which has priority over the casing pressure reducing regulator portion of the pilot. When the fluid operated valves open, casing pressure begins to decrease and the surface controller on the injection gas line opens. When the liquid slug reaches the surface, tubing pressure increases and the tubing cutoff closes and prevents the surface controller from reopening until the tubing pressure decreases.

After the fluid operated valves close, the tubing pressure decreases and the tubing cutoff goes out of service. The pressure reducing regulator portion of the pilot opens the surface controller and permits the casing pressure to increase rapidly to the set closing pressure of the pressure regulator. A typical well hookup using this type of pilot is shown in Figure 17.

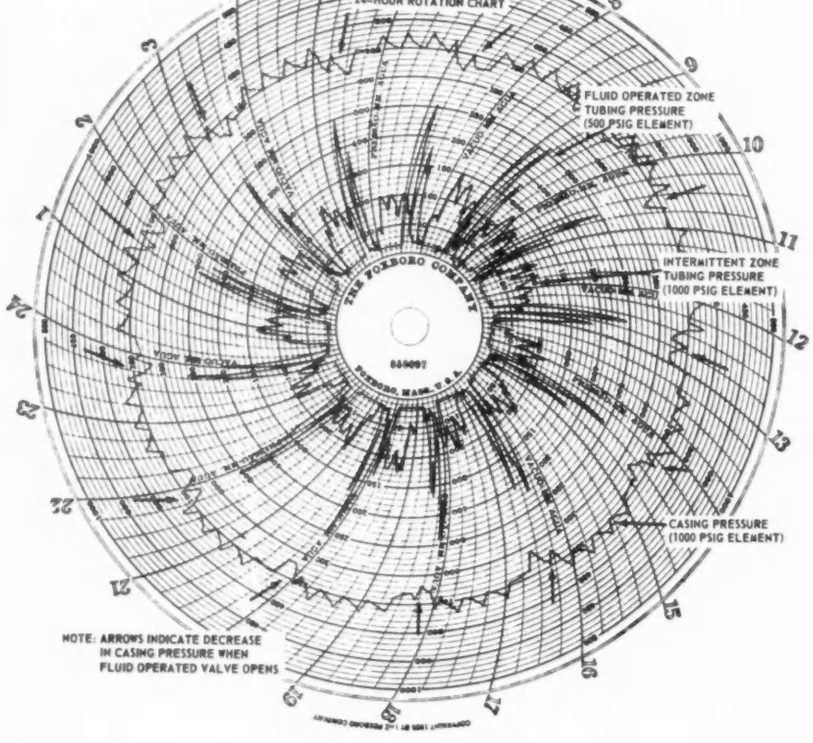

24-HOUR ROTATION CHART
FLUID OPERATED ZONE TUBING PRESSURE (500 PSIG ELEMENT)
INTERMITTENT ZONE TUBING PRESSURE (1000 PSIG ELEMENT)
CASING PRESSURE (1000 PSIG ELEMENT)
THE FOXBORO COMPANY
FOXBORO, MASS., U.S.A.
NOTE: ARROWS INDICATE DECREASE IN CASING PRESSURE WHEN FLUID OPERATED VALVE OPENS

FIGURE 18: Three-pen pressure recorder chart obtained from dual gas lift installation with both zones being lifted with common injection gas source. Intermittent zone does not produce during gas injections immediately following opening of fluid operated valves due to decrease in casing pressure.

Combination time cycle and pressure control pilot for gas lifting duals with common injection gas source. When one zone of a dual is gas lifted using casing pressure operated intermittent valves and the other zone is either a continuous flow or a fluid operated installation, a combination time cycle-pressure control pilot is recommended for the surface controller on the injection gas line. The surface injection casing pressure required to lift the continuous flow or fluid operated zone must be slightly less than the closing pressure of the operating intermittent gas lift valve for the other zone so that the intermittent valve will close between the time cycle controlled gas injections.

The pressure in the casing must be the same when the surface controller opens to have the same increase in casing pressure during a set duration of gas injection. If the casing pressure is too low when the controller opens, the opening pressure of the operating intermittent valve will not be reached during an injection gas cycle and the intermittent zone will not produce.

The three-pen pressure recorder chart in Figure 18 was obtained from a dual installation in which one zone was being gas lifted using casing pressure operated intermittent valves and the other zone was being lifted using fluid operated valves. Every time the fluid operated valves opened, the casing pressure decreased approximately 60 psi. Therefore, the intermittent zone was not lifted during the next one or two injection cycles depending upon how long the fluid operated valves remained open.

For this well, the pressure control portion of the pilot would be adjusted to maintain a minimum casing pressure of approximately 690 psig. When the fluid operated valves opened and the casing pressure decreased below 690 psig, the surface controller would open and maintain this pressure and the intermittent valve for the other zone would open during each time cycle controlled injection gas cycle.

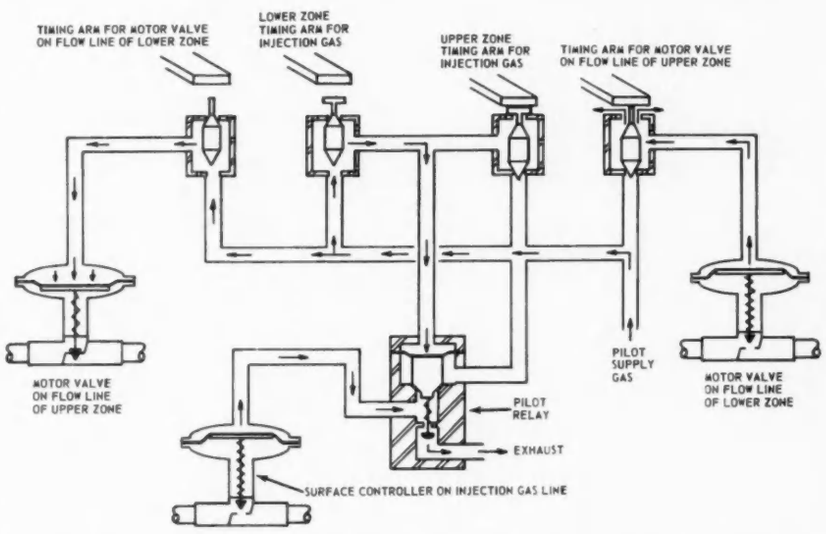

TIMING ARM FOR MOTOR VALVE ON FLOW LINE OF LOWER ZONE
LOWER ZONE TIMING ARM FOR INJECTION GAS
UPPER ZONE TIMING ARM FOR INJECTION GAS
TIMING ARM FOR MOTOR VALVE ON FLOW LINE OF UPPER ZONE
MOTOR VALVE ON FLOW LINE OF UPPER ZONE
PILOT SUPPLY GAS
MOTOR VALVE ON FLOW LINE OF LOWER ZONE
PILOT RELAY
EXHAUST
SURFACE CONTROLLER ON INJECTION GAS LINE

FIGURE 19: Schematic of pilot for time cycle control for intermittent production of duals with common injection gas source by alternately closing flow lines and injecting gas. Illustrates lifting lower zone with upper zone shut-in.

Multiple timing arm time cycle control pilot for intermittent lift of both zones of dual with common injection gas source. The pilot shown in Figure 19 was designed for intermittent gas lifting of both zones of a dual by a common injection gas source. Three direct-acting motor valves are required. A motor valve with a large port must be installed on the flow line for each zone in addition to the controller on the injection gas line.

The pilot for the controller on the injection gas line has four timing arms: two govern the opening and closing of the motor valves on the flow lines while the other two regulate the volume of gas introduced into the casing for lifting each zone. This hook-up prevents one zone from using all or most of the available injection gas.

The timing wheel and pin arrangement for the pilot are designed to keep the flow line of one zone shut-in for the length of time required for the produced slug from the other zone to surface. Adjustment of the timing arms permits variation in the duration of gas injection for each zone. Thus, the most efficient injection period can be established for each zone independently. A typical well hookup using this type of pilot was described in the article "Intermittent Gas Lift Operation Is Successful," WORLD OIL, December 1958).

The importance of surface control of injection gas cannot be over emphasized. This is particularly true if the volume of gas available for gas lifting is limited. This article has discussed only a few of the more widely used surface injection gas control pilots and hook-ups.

There are many other pilots being used today. One is designed to prevent the surface controller from opening unless the injection gas line pressure is sufficiently high. This pilot can be modified to keep the controller closed until the casing pressure decreases below a set value. In other words, the line pressure must be high and the casing pressure low before the controller on the injection gas line will open. These pilots are recommended for a small closed rotative system where one or two wells can "starve" other wells in the system.

Time cycle pilots with a high pressure control are recommended for some macaroni installations to prevent excessive pressure buildup in the small annuli. Also, a high pressure control pilot has been useful in reducing the gas requirement for an intermittent well having an emulsion problem. This type of well requires more gas than a well without an emulsion problem. An excessive increase in casing pressure will open upper valves and cut off part of the liquid slug. The high-pressure control allows adequate injection gas volume per cycle to lift the slug without excessive casing pressure buildup.

When an operator has a special injection gas control problem, he should contact a gas lift equipment manufacturer. Generally, similar problems have occurred and the best type of injection gas surface control can be recommended.

—The End

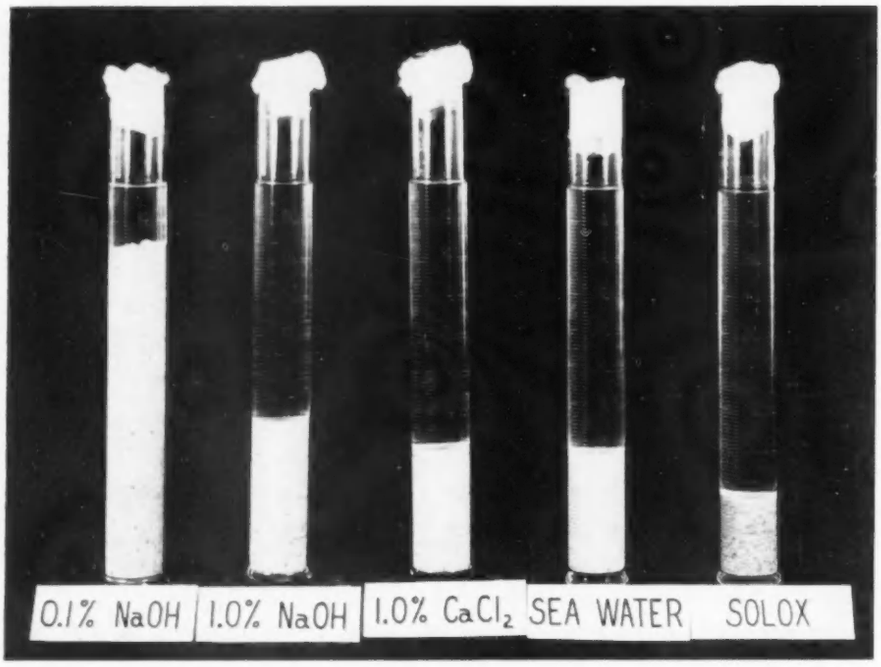


FIGURE 1—Bentonite will acquire different swelling properties in certain aqueous solutions.

Thinning agents control flow properties of mud

A thorough understanding of the mechanism of mud thinning agents will cut drilling costs

By William C. Browning
Research Manager Milwhite Mud Sales Co., Houston

AN ECONOMIC drilling program is one which costs the least in chemicals, equipment and time. The basis for such a program with rotary drilling techniques is a drilling fluid in which bentonites do not swell. This is recognized in the growing trend toward gyp and other inhibited mud systems. Therefore, even though the mechanism of thinner action is a subject of applied colloid chemistry, the understanding of this mechanism is of economic importance in controlling the flow properties of inhibited muds.

There are many aspects of an economic drilling fluid, but the skills and knowledge involved may be classified broadly as either mechanical or chemical. This article presents one facet of the chemical control of mud, namely, a mechanism by which thinners function in inhibited muds.

The economical control of the flow properties of drilling fluids is dependent on the action of chemical thinners or as they are otherwise known in the literature, deflocculants or dispersing agents. The use of thinners or deflocculants in drilling fluids serves several purposes.

- Reduce viscosity and gelation of muds, enabling more solids to be incorporated before the mud becomes objectionably thick.
- Reduce the rate of filtration because of deflocculation of the clay.
- Enables the density of the mud to be increased by addition of barite without the need for dilution with water.
- Stabilize the flow properties of mud to counteract the effect of electrolytes encountered in the formation drilled. Consequently, the current development of rotary drilling fluids is intimately concerned with the action of deflocculants or thinners.

To adequately discuss the mechanism of thinner action in inhibited muds, it is necessary to understand what is meant by flocculation, inhibition, and deflocculation and how the efficiency of thinners can be measured.

Flocculation. The mechanism of thinner action in muds is of perennial interest and is generally discussed in terms of decreasing the tendency of the suspended clay particles to develop brush heap or gel structure. Why suspensions of clays tend to form brush heap or gel structures is usually given little consideration in these discussions.

"Flocculation" is a term long used in colloid chemistry to denote the "clustering" or "coming together" in a random manner of the suspended particles of a suspension to form aggregates or floccules.

Unfortunately, in the recent literature, flocculated muds have been de-

fined as those in which the clays are converted to an aggregated form characterized by a plate-to-plate parallel stacking of the individual clay particles. This definition is further amplified by stating that the contribution of clays to the viscosity is thereby greatly reduced because the clays act as inert suspended solids. This definition refers to what has long been referred to as "swelling" of bentonite in soils and ceramic literature and completely overlooks the fact that the viscosity of suspensions of non-swelling clays is always increased by fluocculation.

Flocculation is not to be identified with swelling inasmuch as flocculation may occur in suspensions of non-swelling materials such as carbon black, dyes, or kaolins, as well as among suspensions of particles susceptible to swelling such as bentonite or agar agar.

Flocculation is an occuring process and one to which all suspended particles tend unless prevented. Two forces of attraction are usually considered as the causes of flocculation: (1) Partial valence forces, (2) London Van der Waals forces.

Partial valence forces. The attractive force of unsatisfied valences occurring because of the fracture of the clay lattice structure has been advanced as the cause of flocculation of clays.[1] Because colloidal particles, carbon black, dyes, agar agar, as well as clays, flocculate in suspension, it would appear obvious that some mechanism other than partial valence bonds, due to broken crystals, may be involved in flocculation. Partial valence forces may be responsible for attraction between particles under certain conditions, but their action is not general. If they are present, they act independently of London Van der Waals forces.

London Van der Waals forces. The possibility that the London Van der Waals forces could be responsible for attraction between particles of a suspension was first considered by Kallmen and Willstatter[2] and further developed by DeBoer[3] and Hamaker.[4] Ordinarily these forces are thought to have only very short range (about one angstrom). It can be shown, however, that the range of these London forces acting between larger particles is of the order of particle radius, i.e., 10 to several hundred angstrom units.[5, 6] This force is always attractive, always present, and it is not specific. These London Van der Waal forces are akin to gravitation and are not to be considered in terms of positive or negative electrical charges.

Marshall[7] has discussed the application of the theories of Hamaker, Vervey and others to the nature of the attractive forces among clay particles in suspension.

Inhibited mud. The term "inhibited muds" refers to those muds in which bentonites exhibit minimum swelling. More properly, it is the liquid phase of filtrate of these muds that are chemically conditioned to minimize the swelling of bentonite. If dispersion is defined as the breaking up of large particles into small ones then inhibited muds also act to minimize mud making, preserve the bore hole and be inert to water sensitive sands.

Swelling, or increase in volume, is a phenomenon in clays associated with hydration. Although all clays hydrate in water, not all clays swell. Kaolins exhibit little or no swelling in hydration. Sodium montmorillonite characteristically swells in water to many times its dry volume. Calcium and magnesium montmorillonite and hydrous micas, or illites, fall between these two extremes but in general show little volume change.

The volume increase or swelling of bentonite in water is best explained by regarding the clay as colloidal electrolyte.

This concept of bentonite swelling as developed by Foster[8] has a number of interesting implications pertinent to drilling fluid technology.

The advantages of brines or inhibited muds as completion fluids is well known. Only the lack of control of flocculation, deflocculation effects, i.e., flow properties, has limited their application to drilling practices. For this reason the mechanism of thinner action in inhibited muds is of interest.

Deflocculation. The thinning or deflocculation of clay suspensions was probably first systematically studied by Johnson and Norton.[9] Their work at that time represented a notable advance in the technology of treating aqueous suspensions of clays and tended to dominate theoretical considerations concerning such systems for almost a decade. The mechanism of deflocculation was widely interpreted in terms of coulombic or partial valence attraction forces and double layer or zeta potential repulsion. Complete deflocculation was regarded to be possible only when hydroxyl ions were present in the water surrounding the clay particles and when the positive ion was monovalent and preferably sodium.

Following these concepts, the action of deflocculants or thinners was primarily explained on the basis of calcium, magnesium or polyvalent ion sequestration or precipitation.[10] The mud engineers' techniques of handling soda base or phosphate muds by treating out contaminants are based on these concepts.

There are indications, however, that Johnson and Norton's interpretation of the mechanism of deflocculation do not cover all known facts. There is known deflocculation of carbon black in a polar media in which charge effects are absent. There are known instances of deflocculation in aqueous systems in which no charge effects were detectable.

It has been shown that deflocculation of clays is not attributable to the exchange of cations, nor is the presence of free hydroxyl necessary for deflocculation. It has been shown[11] that deflocculation of clays may be achieved by sodium hexametaphosphate when the only cation present was sodium, which clearly indicates that the dispersing action of complex phosphates is not to be explained solely on their ability to sequester such ions as calcium or magnesium, facilitating the formation of a sodium ion double layer.

In general, however, the double layer theory of colloidal stability or deflocculation continues to dominate the thinking concerning thinning action.

Double layer effects and their relation with long-range London Van der Waals forces to account for the stability of hydrophobic colloids have been developed as a quantitative theory by Vervey and Overbeek.[12]

Implicit in the assumption of long-range attractive forces, however, is the concept that *any physical barrier* about the suspended particles will oppose the actual contact or coming together of these particles and thus modify flocculation and the rheological properties of the suspension.

Physical barriers may be created

about the suspended particles by adsorption of water although not to the extent of the hydration shells of earlier colloid theory.[13]

Physical barriers may be created by the adsorption of macro-molecular substances that possess structural viscosity due to the in of immobilization of dispersion media, or by adsorption of materials that create a high viscous layer about the suspended particles.[14, 15, 16]

There are two mechanisms that may give colloidal stability or deflocculation:

- Electrokinetic stabilization which is a stabilization of a rather fragile sort based on the concept of such materials as sodium carbonate, silicate or phosphate.
- Physical chemical or mechanical stabilization which is a fairly rugged stabilization afforded by the adsorption of organic polyelectrolytes and involves the formation of viscous physical barriers independent of, or concommitant with, electrical double layers.

Evaluation of thinner action. Inasmuch as dispersing agents or thinners are used in mud and elsewhere to control flow properties, it is natural that rheological means be used to evaluate the effectiveness of these agents. Rheological evaluation of the potency of thinners is an effective procedure if proper consideration is given to the various factors involved in the flow properties of suspensions.[17]

In such evaluations it is essential to distinguish between viscosity effects due to the volume of the suspended solids and particle interaction or flocculation.

Deflocculation is a term long used to denote the breaking up of floccules into individual particles and maintaining the particles as individual units in the suspension.

For any given suspension the consistency (viscosity-gels) will be increased by flocculation and decreased by deflocculation. The magnitude of the viscosity or gel values in any suspension will be determined by the volume concentration of the suspended particles, thus a quite fluid mud may be obtained with the clay in a well flocculated state providing the clay solids are low enough. Conversely, if the volume concentration of clay solids in the mud is relatively high, the mud must be well deflocculated to maintain low viscosity and gel values.

Since the volume concentration of the suspended solids is so very important in determining the number values of viscosities and gels, a suspension composed of swollen bentonite in a deflocculated condition may actually be thinned by converting it to a non-swollen flocculated state.

These effects are illustrated in Figure 2 where it is shown that a phosphate treated bentonite suspension lowers viscosity and gel values through deflocculation. If, however, the same weight concentration of bentonites are hydrated in alcoholic solutions which limit swelling of the bentonite because of repressed dissociation of the inter layer cations, the viscosity and gel values of these suspensions are drastically reduced even though microscopic observation shows that the suspensions are in a well flocculated state.

On the other hand, suspensions of kaolins or illites prepared in alcoholic solution will show higher viscosities and gel values because of increased flocculation. Flocculation is increased because hydrolytic dissociation of surface adsorbed cations is decreased in alcoholic solutions. Reduction of this dissociation, of course, decreases the repulsive force of the electrical double layer permitting the Van der Waals attraction forces to predominate.

The kaolin or illites do not swell, hence the alcoholic environment has no effect on the volume concentration of the suspended clays and the increased flocculation is evidenced by increased viscosity and gels. For this reason then, the flow properties of suspensions of non-swelling clays are

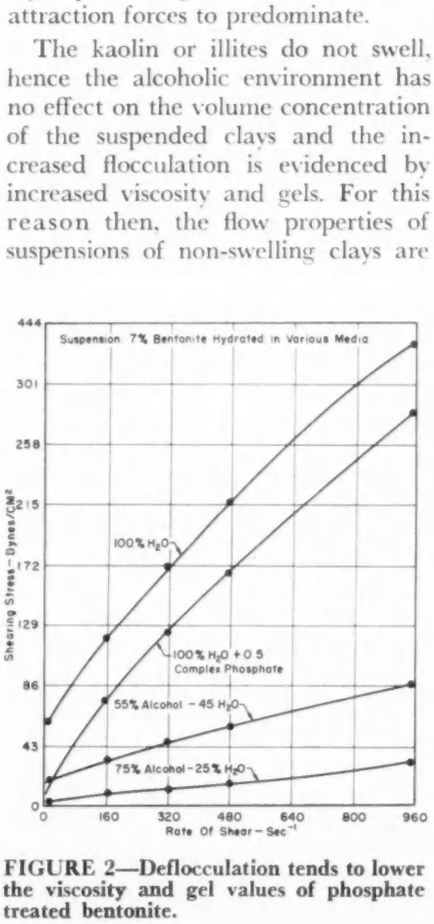


FIGURE 2—Deflocculation tends to lower the viscosity and gel values of phosphate treated bentonite.

excellent indications of the degree of deflocculation of the system, whereas, the flow properties of suspensions of mixtures of bentonite and non-swelling clays are an uncertain index of either the degree of deflocculation or of swelling.

Mechanism of thinner action in inhibited muds. If inhibited muds consist of solutions of electrolytes of sufficient ionic strength to repress the dissociation of base exchange ions of bentonite it is apparent that the degree of deflocculation afforded by electrokinetic stabilization will be feeble in such systems. In other words, phosphates are ineffective thinners for brine muds for the simple reason that the ion concentration of the mud filtrate is sufficiently high to prevent or minimize the dissociation of the adsorbed phosphate. Consequently, the repulsion afforded by electrical charge is very weak or absent and flocculation occurs because the Van der Waals attractive forces are unopposed.

Degrees of colloidal stability or deflocculation can be achieved in inhibiting media by treating the suspension with certain organic polyelectrolytes capable of multi-layer adsorption on the clay particles. This multi-layer adsorption creates highly viscous or structural layers about the suspended particles providing a mechanical stabilization factor.

Drilling mud thinners, capable of functioning in this manner, include organic polyelectrolyte agents capable of providing electrokinetic stabilization as well as mechanical stabilization.

To illustrate the differences between these two types of stabilization refer to Table 1, wherein data is given characteristic of electrokinetic stabilization. It can be noted that very small treatment of deflocculants on the weight of the clay provides a drastic thinning effect. Maximum thinning occurring in the range of 0.1 to 0.5 percent of the agent on the weight of the clay. As the concentration of the agent is increased, the viscosity of the clay suspension increases. This may be demonstrated as being due to repression of ionization of the polyelectrolyte adsorbed on the clay because of increased ionic concentration of the unadsorbed polyelectrolyte in the dispersion media. This effect is the conventional "over-treatment" phenomenon encountered in drilling mud practice.

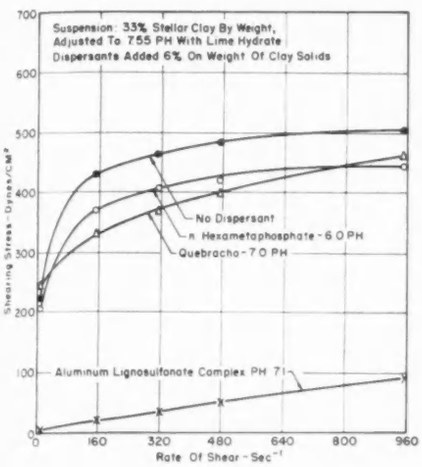

Suspension: 33% Stellar Clay By Weight,
Adjusted To 7.55 PH With Lime Hydrate
Dispersants Added 6% On Weight Of Clay Solids
No Dispersant
n. Hexametaphosphate - 6.0 PH
Quebracho - 7.0 PH
Aluminum Lignosulfonate Complex PH 7.1
Shearing Stress - Dynes/CM²
Rate Of Shear - Sec⁻¹

FIGURE 3—Deflocculation of kaolin is shown in a normal salt solution.

With the electrical double layer any increase in electrolyte in the dispersion media will decrease ionization tending to collapse the double layer. Collapse of the double layer, of course, means that the electrical repulsion between the particles vanishes and the Van de Waals attraction continues to manifest itself causing flocculation. In Table 1, the effect of a contaminating electrolyte such as sodium chloride on collapsing the double layer by ionic repression is also shown. In this case the organic polyelectrolyte, sodium lignosulfonate, is as adversely affected as the phosphates because in this instance the mechanism of thinning action is the same.

In Figure 3, the characteristics of effective mechanical stabilization by treatment of a clay suspension with a suitable polyelectrolyte is shown.

In this instance a 33 percent kaolin clay neutralized with lime and suspended in a one normal salt solution is of course highly flocculated as shown in the no-dispersant curve. Treatment of the suspension with 6 percent of sodium hexametaphosphate affords very little thinning effect, as does treatment with 6 percent of neutral sodium tannate. On the other hand, treatment with 6 percent of a lignosulfonate modified to give multilayer adsorption on the clay under this condition achieves a high order of deflocculation as indicated by the Newtonian flow curve of the aluminum lignosulfonate complex treatment, as well as active Brownian movement of the clay particles observable ultra-microscopically.

In Figure 4, the characteristics of electrokinetic stabilization, as well as mechanical stabilization, afforded by a calcium lignosulfonate is given. In Curve 1, the 51 percent kaolin clay is shown to be drastically thickened by small additions of calcium hydroxide.

If the uncontaminated suspension is treated with ½ pound per barrel or 0.35 percent of calcium lignosulfonate, the system is well deflocculated as shown by the drop in shear resistance from approximately 500 to approximately 100 dynes per centimeter. However, because the concentration of lignosulfonate only affords electrokinetic stabilization, increasing contamination in the form of calcium hydroxide rapidly flocculates the clay through collapse of the double layer as shown in Curve 2.

If the suspension is treated with about 1 pound per barrel or 0.76 percent lignosulfonate as shown in Curve 3, some deflocculation results in the uncontaminated suspension. It is not as great, however, as that afforded by the ½ pound-per-barrel treatment. This is the characteristic "over-treatment" effect occurring in electrokinetic stabilization, i.e., there is sufficient unadsorbed lignosulfonate dissociating in the dispersion media to repress the ionization of the adsorbed lignosulfonate giving weaker double layer effects. However, by beginning to increase contamination in the form of calcium hydroxide, the degree of deflocculation is increased and the system becomes thinner. This is because the calcium hydroxide in the dispersion media actually forces adsorption of extra lignosulfonate upon the clay particles. This increased adsorption gives a small amount of mechanical stabilization to supplement some electrokinetic stabilization. This particular

TABLE 1—Small Treatments of Deflocculants on the Weight of Clay Suspension Will Show Drastic Thinning Effects

Suspension: 40.32 percent Bandy Tan by Weight Adjusted to 7.10 PH with Sodium Hydroxide

Dispersion Media	Concentration of Deloc. % on Clay	Apparent Viscosity at 960 Sec⁻¹ Shear	
		Phosphate	$NaLSO_3$
Water	0	25.0	25.0
	0.05	5.3	7.3
	0.10	4.5	4.7
	0.20	4.5	4.7
	0.50	5.0	4.7
	1.0	5.3	5.0
	2.0	5.5	5.5
	4.0	6.0	6.0
	6.0	8.0	9.0
	8.0	17.0	11.0
0.01 N NaCl	0.10	14.3	16.5
0.05 N NaCl	0.10	34.0	25.5
0.10 N NaCl	0.10	39.0	28.3
0.50 N NaCl	0.10	46.2	35.0
1.00 N NaCl	0.10	55.5	46.0
2.00 N NaCl	0.10	68.0	58.5

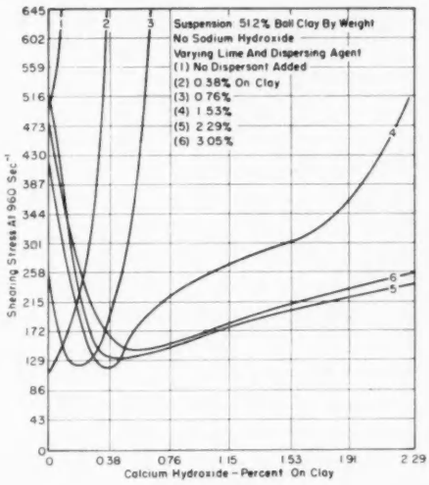


FIGURE 4—The effect of calcium lignosulfonate on lime treated ball clay suspensions is shown above.

curve is characteristic of the so-called low-lime treated muds, where, characteristically, if the lime drops too low, the system thickens up a small amount, and if the lime increases slightly it thickens up considerably. Obviously, chemical maintenance at the point of optimum treatment is rather difficult to maintain.

If the lignosulfonate treatment is increased to 2 pounds per barrel in this system, increased mechanical stabilization is afforded and there is more latitude in maintaining a fluid suspension. Increasing the lignosulfonate treatment to 4 pounds per barrel or 2.25 percent gives wide latitude in maintaining a deflocculated suspension as does treatments at 6 pounds per barrel.

It should be noted that in the 4-6 pounds per barrel range that the deflocculation of the uncontaminated slurry is practically absent. In other words, the concentration of lignosulfonate is sufficient to effectively prevent electrokinetic stabilization. On the other hand, the increased adsorption of the lignosulfonate in the presence of the lime contamination gives a mechanical stabilization of a high order of effectiveness. A slight increase of viscosity, as evidenced by the 6 pounds per barrel treatment is due essentially to the magnitude of the adsorption layers themselves.

As shown in Figure 5, in each of the points of optimum chemical treatment there is essentially Newtonian flow curves indicating a high order of deflocculation for this clay suspension. Therefore, both rheological evidence as well as ultra-microscopic observation indicates that an actual

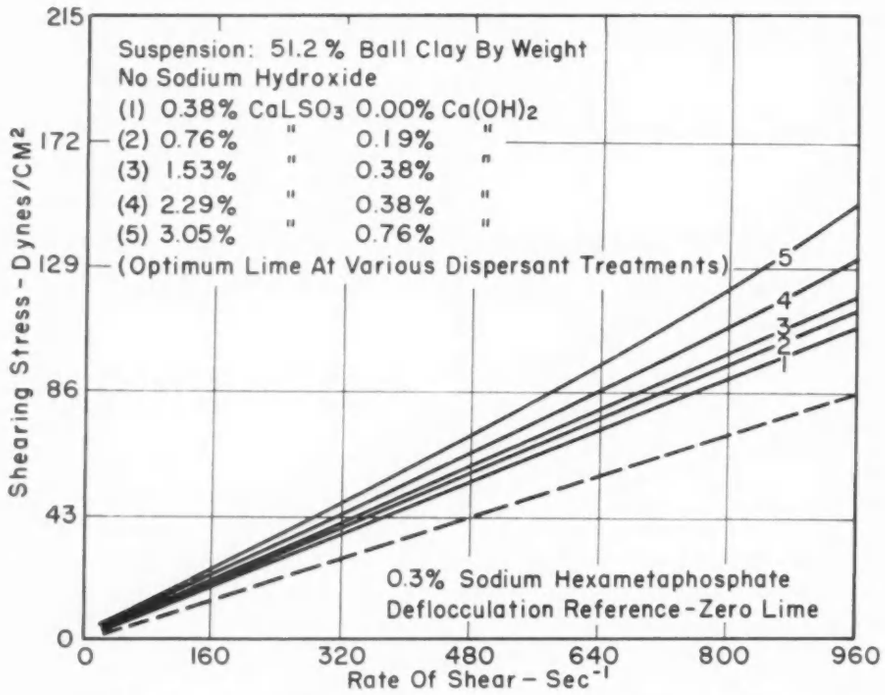


FIGURE 5—A high order of deflocculation is shown for a 51.2 per cent clay treated with a dispersing agent and lime.

and a high degree of deflocculation can be achieved in a calcium ion environment by treatment with a suitable thinner. The degree of deflocculation, as shown by these curves, compares favorably with the deflocculation afforded by sodium hexametaphosphate in an uncontaminated system. The slight increase in viscosity as the lignosulfonate is increased reflects the increased volume of suspended solids due to the polymolecular adsorption of the lignosulfonate.

Similar curves may be developed with clay suspensions at higher levels of calcium contamination by treating the appropriate agents.

The mechanism of thinning action by organic polyelectrolytes may be further clarified by examining some of the solution properties of these organic agents themselves.

The properties of lignosulfonates from Hemlock and Aspen prepared by a commercial lime precipitation process will be examined. In Figure 5, viscosity concentration curves of sodium and calcium lignosulfonates from hardwood and softwood are shown. The specific viscosity (relative viscosity minus one) increases rapidly as solution concentration exceeds 20 percent. This is a characteristic behavior of polyelectrolyte thinners.

If these organic agents are chemically constituted so that they are adsorbed on the clay particles, then adsorption forces effect the concentration of the agent about the surface of the particle. Hence, in the clay suspension, a condition obtains where the agent in the dispersion media, as indicated by a lignosulfonate concentration of 5 percent or less, has an exceedingly low viscosity, approximating that of water. Whereas, near the surface of the particle, due to the formation of condensed layers of adsorption forces, the viscosity of the lignosulfonate is many times that of water, as indicated by the 25 or 30 pound concentration viscosities. The forces of adsorption are exceedingly powerful and it may be demonstrated that this order of concentration in the adsorption layers is well within the realm of possibility. Consequently, the high viscosity of the adsorbed organic polyelectrolyte about the particles of suspended clays prevent them from coming together close enough for the Van de Waals attraction forces to manifest themselves causing flocculation.

It is necessary, however, that these agents in high concentration be viscous in character. As shown in Figure 6, even in the 25 to 30 percent concentration, the lignosulfonates exhibit Newtonian flow characteristics. It has been found that when electrolyte concentration in the dispersion media begins to salt out the organic agent so that they no longer exhibit Newtonian flow characteristics in the high concentration, then they lose their effectiveness as colloidal stabilizers or thinners for inhibited muds. This is reasonable for if the thinner cannot

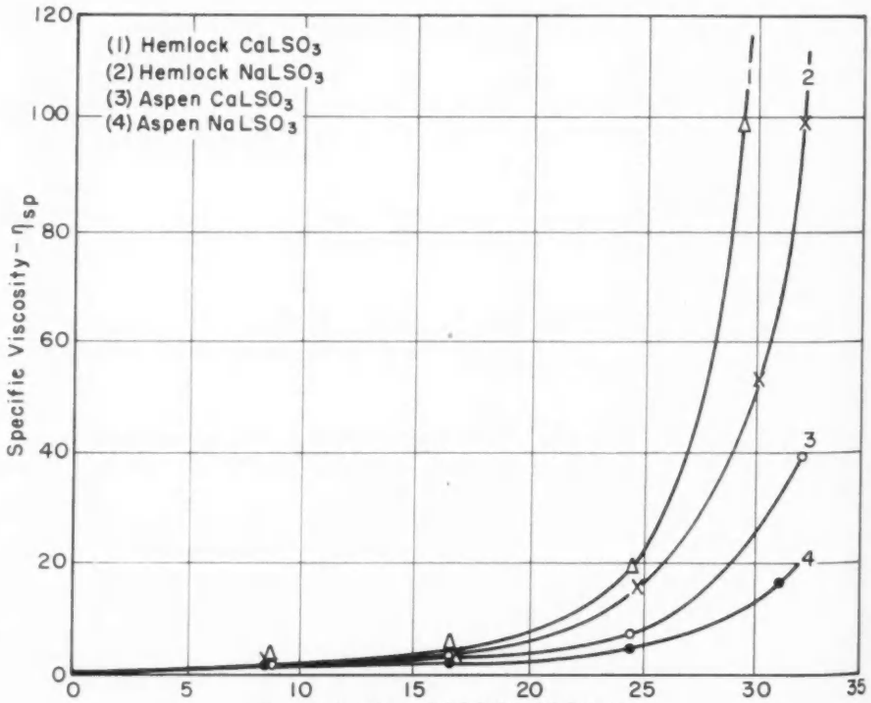


FIGURE 6—Sodium lignosulfonate, as indicated by Curve 2, is more effective as an electrokinetic than calcium lignosulfonate; however, calcium lignosulfonate, as shown by Curve 3, is more effective as a thinner in calcium contaminated suspension.

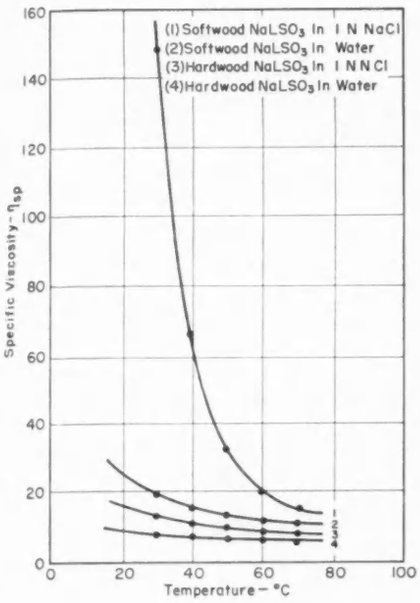

(1) Softwood NaLSO3 In 1 N NaCl
(2) Softwood NaLSO3 In Water
(3) Hardwood NaLSO3 In 1 N NaCl
(4) Hardwood NaLSO3 In Water
Specific Viscosity - ηsp
Temperature - °C

FIGURE 7—Flow curves of sodium lignosulfonate are shown from hardwood and softwood in water and normal sodium chloride solutions.

be adsorbed in a multi-layer manner to give a high concentration at the clay surface, then it cannot create the viscosity differential between the surface of the clay particle and the dispersion media sufficient to maintain stabilization of the clay particles.

Previous work has indicated that sodium lignosulfonates, as indicated in Curve 2, will be somewhat more effective as electrokinetic stabilizers, but a calcium lignosulfonate, as indicated in Curve 1, Figure 6, will be a more effective thinner in calcium contaminated suspension. This is in accord with the concept of a viscosity differential between the highly concentrated adsorption layer and the dispersion media. It has been demonstrated that the hemlock lignosulfonates are noticeably more effective as thinners for inhibited muds than the asper lignosulfonates and this is reflected in the characteristics of their viscosity concentration curves.

As previously indicated, insofar as Newtonian flow characteristics of the polyelectrolyte solution are maintained the polyelectrolyte will effectively stabilize suspensions, and the higher the Newtonian viscosity of the concentrated solution the more effective the stabilizer. In Figure 7 is shown the flow curves of sodium lignosulfonates from hardwood and softwood in water and in one normal sodium chloride solution. Here again the softwood lignosulfonates are more effective thinners in sodium chloride solutions than are the hardwood lignosulfonates, although the differences tend to level out as temperature is increased.

This salt effect is frequently observed when treating field muds with polyelectrolyte thinners, that is addition of some salt lowers viscosity and gels.

Theories of behaviors of mechanisms to be useful, however, must do more than explain known effects. If they are to be of value, they must be capable of guiding developments and of predicting results. The concept of thinner action presented here can be used to guide the development of inhibited mud systems. This concept can also be used to develop improved thinners for inhibited systems. The results of such a development are shown in Figure 8. The aspen lignosulfonate is inferior as a thinner to a softwood lignosulfonate. However, by appropriate organic reactions the polyelectrolyte character of the aspen lignosulfonate may be modified to give thinner action that is in substantial improvement over the softwood lignosulfonate. Curves 1 and 2 are an aluminum complex lignosulfonate used for illustration in this article and a ferrichrome lignosulfonate respectively.

In summation, it may be stated that muds or suspensions may be deflocculated by two mechanisms:

- By an electrokinetic double layer effect and,
- By polymolecular adsorbed condensed layers.

Electrokinetic stabilization, as exemplified by phosphate treatment or sodium tannate muds, is highly effective with a low concentration of thinner (0.5 pound per barrel) in noncontaminated systems, but is especially susceptible to the effect of contaminating electrolytes. To achieve satisfactory stability in the presence of inhibiting concentrations of electrolytes, thinners soluble in these filtrate environments and capable of multilayer adsorption to give a high viscosity adsorption layer must be used. Because an adsorption layer of finite thickness is needed, greater quantities of thinner must be used (4-6 pounds per barrel) than is needed for electrokinetic stabilization.

Rheological techniques may be used to evaluate thinner action as well as thinner agent chemistry.

For the field treatment of muds, however, it is to be remembered that

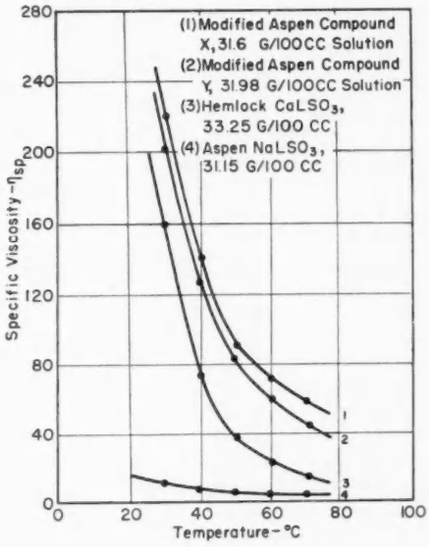

(1) Modified Aspen Compound X, 31.6 G/100CC Solution
(2) Modified Aspen Compound Y, 31.98 G/100CC Solution
(3) Hemlock CaLSO3, 33.25 G/100 CC
(4) Aspen NaLSO3, 31.15 G/100 CC
Specific Viscosity - ηsp
Temperature - °C

FIGURE 8—Different types of lignosulfonate are shown as thinning agents. Aspen lignosulfonate is considered an inferior thinner than softwood lignosulfonate.

the flow properties of the mud are but the reflection of the colloid chemistry of the mud and may be controlled through knowledge of that chemistry. In mud programming, therefore, the filtrate environment suitable for most economic drilling for the geology of the area under consideration should be first determined. The proper rheology for the engineering and rig requirements may be developed for any filtrate environment through manipulation of the factors determining the flow properties of suspensions.

REFERENCES

[1] Loomis, A. G., Ford, T. F., and Fidiam, J. F.: Trans. AIME (1941) **142**, p. 86.
[2] Kallman, H., and Willstatter, J.: Die *Naturwissenschaften* (1932) **20**, p. 952.
[3] DeBoer, J. H.: *Trans. Faraday Soc.* (1936) **32**, p. 21.
[4] Hamaker, H. C.: *Roc. Trav. Chem.* (1936) **55**, p. 21.
[5] Overbeek, J. Th. G., and Sparnay, M. J.: *Discussions of Faraday Soc.* (1954) No. **18**, p. 12.
[6] London, F. Z.: *Physic* (1930) **63**, 245.
[7] Marshall, C. E.: *The Colloid Chemistry of the Silicate Minerals*, Academic Press (1949) p. 155.
[8] Foster, M. D.: *Clays and Clay Minerals*, National Academy of Sciences—National Research Council, Publication 395, p. 205.
[9] Johnson, A. L., and Norton, F. H.: *Jour. Am. Ceramic Soc.* (1941) **24**, p. 189.
[10] Asdell, B. K.: *Paper Mill News* (1947) May 31.
[11] Van Wazer and Besmertnuck: *Journ. Phys. Chem.* (1940) **54**, p. 89.
[12] Vervey, E. J. W., and Overbeek, J. Th. G.: *Theory of the Stability of Lyophobic Colloids*, Elsevier Pub. Co., Amsterdam (1948).
[13] Lawrence, W. G.: *Jour. Am. Ceramic Soc.* (1958) **41**, p. 147.
[14] Rehbinder, P., and Wenstrom: *Kolloid Z* (1930).
[15] Derjaguin, B. V.: *Trans. Faraday Soc.* (1940) **36**, p. 203.
[16] Heller, W., and Pugh, T. L.: *Journ. Chem. Physics* (1954) **22**, p. 1778.
[17] Browning, W. C.: *Paper 557-G* (1955) 30th Ann. Fall Meeting, Petroleum Branch AIME.

ACKNOWLEDGMENT

This article is based on a paper presented at the ninth annual meeting of the Canadian Institute of Mining and Metallurgy, Petroleum and Natural Gas Division, Calgary, Alberta, Canada, May 28-30, 1958.

Photogeology giving rapid coverage in Four Corners

Oil and mining companies, AEC benefit from good aerial geologic evaluation; color effective

By Marshall S. Wright, Jr.
Chief Engineer, Jack Ammann Photogrammetric Engineers, Inc.
San Antonio, Texas

GEOLOGICAL INTERPRETATION of aerial photographs is an effective means of evaluating large areas in the Four Corners region, as well as many other oil-prospective districts of the world. Through use of a precision mapping camera from 10,000 feet in clear weather, distortion-free vertical photographs can be acquired to provide essential geological details in three dimensions at considerable savings in time and money as compared with ground methods.

These tools are particularly valuable in a region such as the San Juan Basin in the Four Corners area of New Mexico, Arizona, Utah, and Colorado. This hot oil area is vast, rugged, and relatively remote. Existing map information is sparse. But a specially equipped photographic airplane, flying back and forth across the area to be mapped, can photograph hundreds of square miles in a few hours.

Good weather essential. Crystal clear days, during which no clouds or cloud shadows obscure the area and haze is negligible, are required for this photography. The number of such days which can be expected per month varies widely, of course, depending upon the location and the time of the year. For example (to take extremes), in Yuma, Ariz., one can expect 28 photographic days in October, whereas in Miami, Fla., less than one day per month can be expected in July or August. The year-round average in the United States is about five days per month.

Mosaics compilation. Once the necessary aerial photography is obtained, the photogrammetric engineer can go to work preparing various map products. The simplest, and yet one of the most effective types of map which can be compiled from aerial photographs is the aerial mosaic. A mosaic can be prepared from two, or from 20,000 photographs. During mosaic compilation, each photograph is processed individually, and all effects of tip and tilt introduced by the camera not being truly vertical at the instant of exposure are removed and each photo is brought precisely to scale. The corrected mosaic is opposed to the type of mosaic wherein contact prints of the aerial photos are pasted down with no attempt made to correct for scale variations and tip and tilt. Whole mountains have been known to disappear on such mosaics! A professionally prepared mosaic presents a clear and accurate picture of the earth's surface.

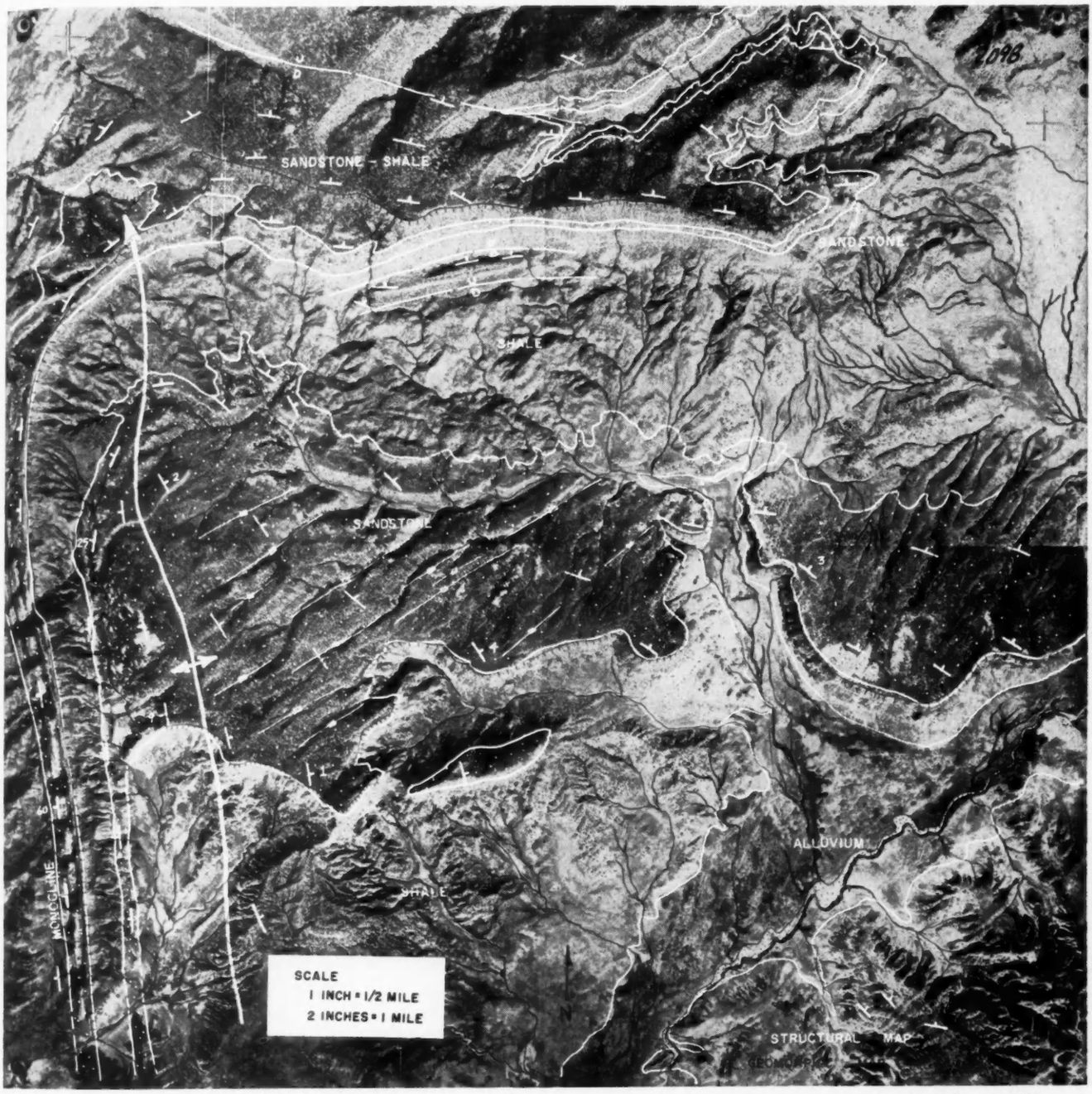
GEOLOGICAL INTERPRETATION

With an aerial mosaic available as an accurate base map and a set of aerial photography contact prints available to provide material for detailed stereoscopic study, the photogeologist is ready to work. Oil companies in the Four Corners have made extensive use of photogeology in planning for oil and gas lease sales by the Navajo and Ute Indians and by government agencies. Usually, these lands are in isolated areas where the cost of geophysical or surface surveys would be prohibitive, or time allowed for preparation of bids is too short for more detailed investigation. The U.S. Geological Survey and the Atomic Energy Commission have prepared photogeological maps of a large portion of the Four Corners for use in their search for uranium and other radioactive minerals.

Nearly all recent USGS oil and gas investigations maps are prepared and compiled by photo interpretation along with field surveys. Mining companies have made extensive use of aerial photos in the delineation and mapping of radioactive ore bearing beds and formations.

Maximum interpretation. The geology of the Four Corners is well reflected in aerial photos. Good rock outcrop and sparse vegetation allow maximum interpretation of geologic features. Identification of structures and delineation of bedding and formation contacts is apparent in interpretation because of the high degree of erosion and lack of soil and vegetative cover.

Shadow effects. Shadows create problems at times, but generally they have little effect in the Four Corners region. Since any image falls on at least three photos, it often is possible to view a shadow-covered cliff on another photo where light conditions are favorable. It also is possible, in some cases, to view a shadow area in photography in an adjacent flight line where light conditions are totally different.



Beard and Bogart, 1959

FIGURE 1—Stream drainage patterns (color) and some surface geological features (white) are provided by a base aerial photographic mosaic and two overlays. The original photography was done from an altitude of about 14,700 feet. Shown is about 25 square miles in the western part of McKinley County, New Mexico. Original scale was 1:31,680 before reduction of about one-third to fit one-page space requirements. One overlay (geomorphology) shows drainage pattern; the other includes reconnaissance geologic survey; structural axes, some surface lithologies and outcrop patterns, attitude of beds, fault traces, etc.

Dip problems. The Four Corners area includes the major San Juan Basin, Paradox and Black Mesa basins and the minor Kaiparowitz, Lucero and Chama basins. Around the limits of these basins, the dip of beds is usually strong to high-angle, changing abruptly to low angle dip basinward. There is little or no difficulty in interpretating strong or high angle dips. But there may be a tendency to assign too high a degree of dip because of photo distortions and change of scale. In the areas of low angle dip, interpretation becomes more difficult and much of it is based on geomorphic expression indicated on the photos. Interpretation is highly dependent on stream pattern and resulting erosional features.

In highly cross-bedded areas, photogeologic interpretation may be more accurate than field survey or reconnaissance since the perspective is of a large unit area and is not confused by small detail. Massive beds in low dip areas are difficult to interpret and much reliance is placed on geomorphology for accurate mapping.

Color photography. Until the recent advent of successful mapping by color aerial photography, photogeology in the Four Corners had been from black and white photos. Color photos may be of great value in the

area because of the array of colors in the rock outcrop. Rock units vary from white through various shades of pink, orange and reds, purple and grays. Each of these rock units is more easily recognized in the color photo, facilitating the delineation of beds and formations for areal geologic mapping.

In black and white photography all colors are reproduced in tones of gray. It is often difficult or impossible to distinguish subtle differences of gray tone, causing interpretation to be incomplete or inaccurate.

From the geologist's viewpoint, color has many advantages. The eye is much more sensitive to color variations than to variations in shades of gray. Hence, finer, more obscure bits of information may be differentiated on color photographs. Use of specialized emulsions for color may provide superior resolution detail, although color photographic and processing techniques must be carefully controlled to avoid significant variation in color shades. Color has a continuous type of emulsion with no "grain" present, whereas black and white photography, of course, has "grain" in it.

Color is highly useful in low angle dip areas of incompetent bedding, such as shales or unconsolidated sandstones. Weathered rock units will have characteristic color that can be traced for accurate mapping. Also, characteristic color of vegetation on a particular rock outcrop is invaluable for tracing bedding.

Geologic evaluation can be broken down into three broad categories: (1) reconnaissance geomorphic study; (2) reconnaissance structural study, and (3) detailed photogeologic study. A brief description of the techniques involved and the results obtained in each of these studies follows.

Reconnaissance geomorphic study. A geomorphic evaluation necessarily is a reconnaissance tool best applied in areas of low structural and topographical relief. Such evaluations are usually made of large areas and the work is best done on relatively small-scale mosaics. Regional patterns are readily apparent on such mosaics and stereoscopic contact prints are used for more detailed analysis where required. The data mapped in a geomorphic study include:

- Drainage in detail
- Soil coloration changes (revealed by photo tone in black and white photography)
- Outcrop pattern; that is, the relationship between escarpments and valleys.

The above mapped data is analyzed on a regional scale where anomalous conditions in the over-all pattern are sought. Drainage, when mapped in detail, frequently shows changes in lithology even though outcrops may be scarce or lacking. The geomorphic map accompanying the area photograph shows a variety of conditions affecting drainage: braided drainage in alluvial areas; fine, feathery drainage indicating badland erosion on shale slopes; parallel linear drainage on dip slopes; dendritic to rectangular obsequent streams flowing against dip; radial pattern drainage flowing down dip around a curved escarpment. When prominent escarpments are superimposed on this drainage pattern, one can interpret structural conditions even though no more data are used.

Reconnaissance structural study. In areas of moderate to high structural and topographic relief where bedrock outcrops are visible on aerial photographs, one can map data of different kinds; that is, data having all visible criteria leading to structural analysis. By using stereo pairs, the following structural data are determined:

- Strike and dip of sedimentary strata; careful measurement can determine the amount of dip
- Faults showing relative movement and amount of throw
- Fracture pattern frequently helpful in relating the area to structural uplift
- Surface structural axes.

The structural map presented in overlay fashion on the photograph (Figure 1) has been annotated showing the above data. Orientation and intensity of the mapped structure are clearly visible not only by means of dip and strike but also through the outcrop pattern, structural latitude, and drainage characteristics. Moreover, the superimposition of these two maps provides a fairly complete areal geologic map.

Detailed photogeologic study. This type of study consists of the mapping and interpretation of all significant geologic data shown on aerial photographs. These data include:

- All drainage in great detail
- Soil coloration changes revealed by photo tone
- Outcrop pattern
- Strike and dip of sedimentary strata
- Faults showing relative movement and amount of throw
- Fracture pattern
- Surface structural axes
- Cultural features such as roads, trails, houses, etc., to show accessibility and facilitate location on the ground
- All mapable geologic formations
- Intra-formational key beds of mapable importance.

The above described data when plotted on one map results in a complete area geologic map.

Fault throw calculations often can be made accurately by photogeologic methods. Quality of the basic photography, experience and care exercised by the interpreter, and quality of instruments used affect the accuracy of such calculations. Generally, results are comparable to all but the most meticulous field work.

In many cases, better fault-throw data can be obtained from photos than in the field. Where a broad or regional view is necessary to pick a bed or mapping contact on both sides of a fault, or where the throw is small, photo work may yield better results. Another such instance may be where the key mapping bed near the fault is obscured by talus or other material; here, the mapping horizon often may be projected on photos to within close limits of its actual position. Sometimes faults can be mapped in grassy areas where nothing can be seen on the ground. In such cases, the trace can be mapped but not the throw.

Maps for reconnaissance geomorphic study usually are on a small scale since the study is of regional nature. The scale is commonly that of the mosaics. Final maps may be in the form of either a reproducible film (Figure 2) or as transparent colored-line overlay placed directly over mosaics.

Final maps for reconnaissance structural study are usually on a larger scale than those for geomorphic studies. Most commonly, they are in the form of a reproducible film. However, the structural data can be

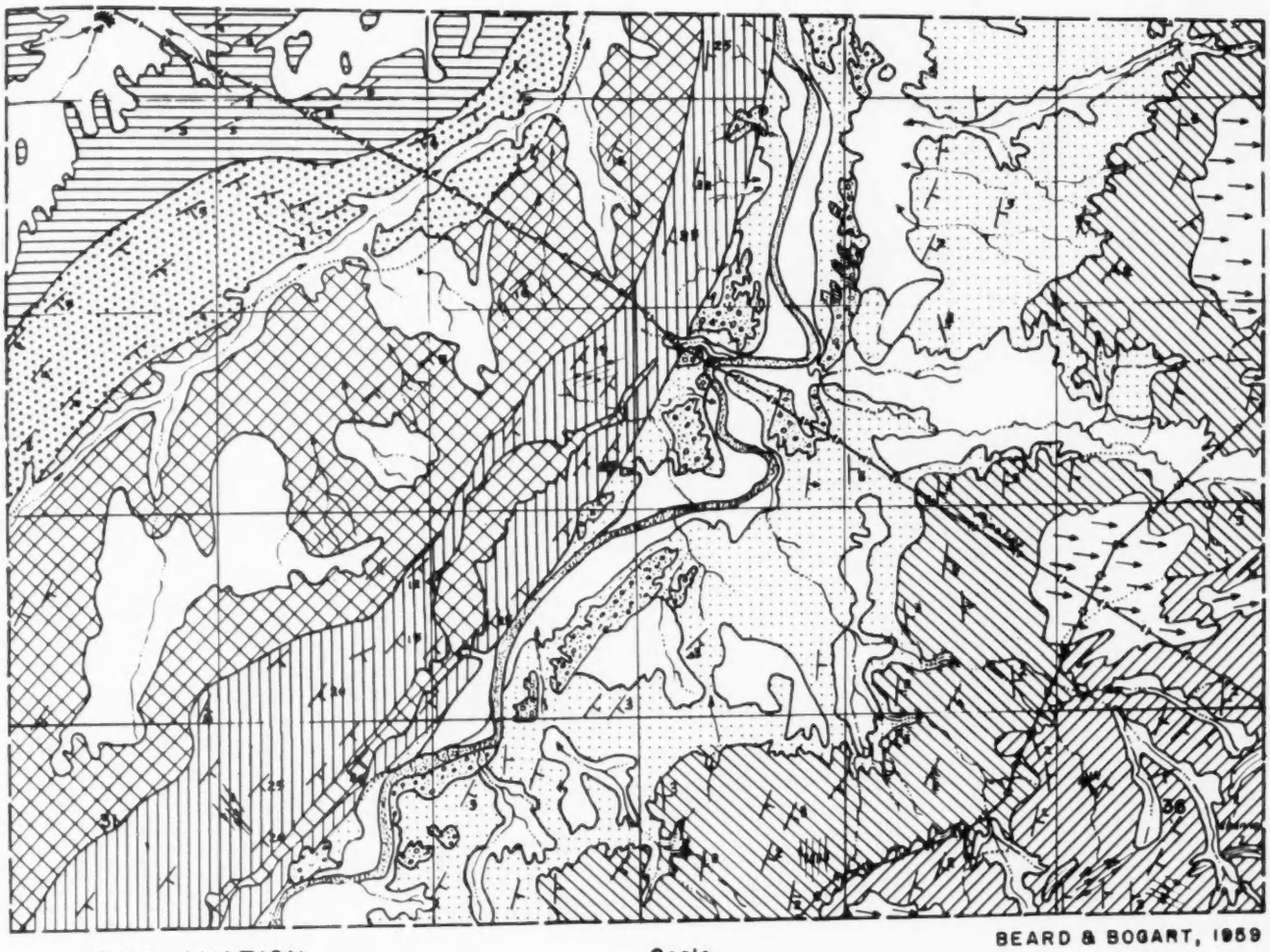


FIGURE 2—This is the detailed geologic map of part of the San Juan Basin compiled from the same mosaic used as a base for Figure 1.

superimposed on mosaics of the study area. Final maps for detailed photogeologic study are printed on good quality rag paper and colored with oil paints. This type of map shows the pattern of mapable formations so that study is facilitated by formations being shown in a variety of colors. The detailed photogeologic map submitted is an example of the latter type of study. In this case, the various formations are delineated by line and dot patterns.

ACKNOWLEDGMENT

The author wishes to express his gratitude to Beard and Bogart, Geologists, Albuquerque, N. M., and to Lee W. Kilgore, Geologist, Farmington, N. M., for their assistance.

About the Author

Marshall S. Wright, Jr., is Chief Engineer of Jack Ammann Photogrammetric Engineers, Incorporated, San Antonio, Texas. Wright received his B.S. degree in Civil Engineering in 1943 at Virginia Polytechnic Institute, in Blacksburg. Following military service, he worked for three years for the United States Geological Survey in the eastern division office in Arlington, Va., and the following four years with Engineer Research and Development Laboratories at Fort Belvoir. He joined Jack Ammann in 1953.

BAKER

PRIMARY CEMENTING EQUIPMENT

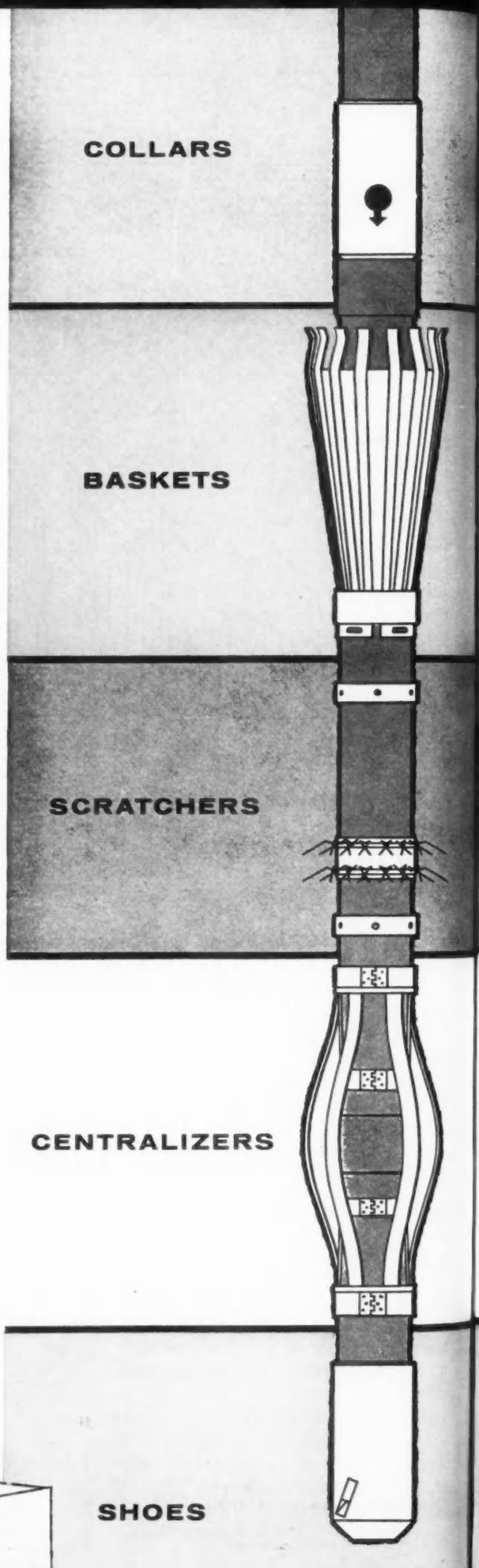
Here are all the products needed for the first step toward profitable production. Look at the variety of Shoes and Collars . . . Baskets . . . Wall Scratchers . . . Casing Centralizers . . . in every type and size to meet your well conditions successfully and economically.

Never before has your supply store been able to offer such a complete line of Practical and Dependable BAKER Primary Cementing Tools!

You get **more** than just a good cement job when you select the balanced combination of Baker Primary Cementing Equipment. For, whether yours is a routine cement job or a "problem" with weak porous zones which must be protected from dangerous pressure surges—you'll get the job done right and preserve maximum productivity.

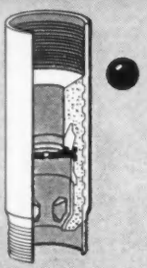
Baker Primary Cementing Equipment is conveniently available at your supply store, backed by the stocks in 64 Baker Branches. Over 400 Baker Servicemen stand ready to provide genuine help with your cementing problems.

BAKER OIL TOOLS, INC.
HOUSTON • LOS ANGELES • NEW YORK

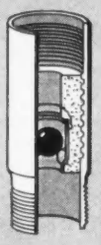


Differential
Fill-Up Collar
Product No. 1091 M&F

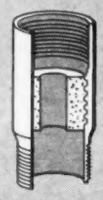
Flexiflow
Fill-Up Collar
Product No. 161 M&F



Circulating Flexiflow
Fill-Up Collar
Product No. 161-D M&F



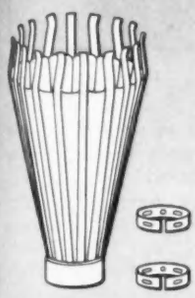
Cement Float Collar
Product No. 101 M&F



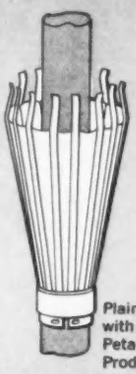
Cement Baffle Collar,
with Hole
Product No. 104 M&F

Cement Baffle Collar,
Solid
Product No, 105 M&F

Triplex
Flapper Valve
Float Collar,
Product No. 134 M&F



Metal Petal Basket,
with Stop Rings
Product No. 343



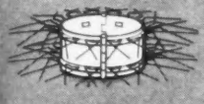
Plain Hook-Up Nipple
with Metal
Petal Basket
Product No. 330

The only complete line of
Primary Cementing Equipment
available through your
supply store.

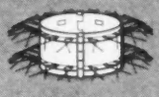
BAKER

OIL TOOLS, INC.

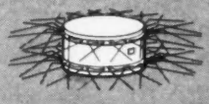
HOUSTON • LOS ANGELES • NEW YORK



Hinge-Lok Wall
Scratcher, with
4½" long wires
Product No. 900-C

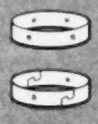


Hinge-Lok Wall
Scratcher, with
2½" long wires
Product No. 900-C

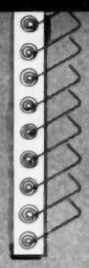


Solid-Ring Wall
Scratcher, with
4½" long wires
Product No. 901-C

Solid-Ring Wall
Scratcher, with
2½" long wires
Product No. 901-C



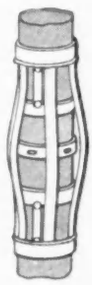
Auto-Grip
Stop Rings
Product Nos.
938 (Solid)
and 939 (Split)



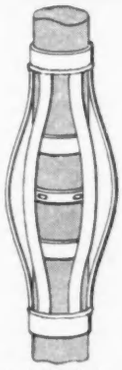
Rotating
Wall Scratcher
Product No. 903

"G-12" Slim Hole
Casing Centralizer
Product No. 910-G

"G-20" Solid-Ring
Casing Centralizer
Product No. 910-G

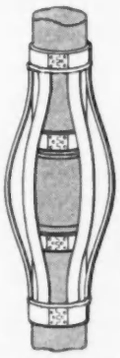


"HN-15" Solid-Ring
Casing Centralizer
Product No. 908-HN

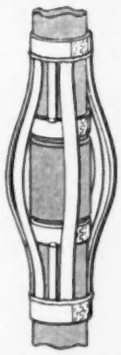


"HN-20" Solid-Ring
Casing Centralizer
Product No. 908-HN

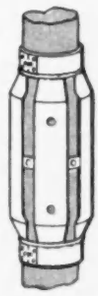
"H-15" Hinge-Lok
Casing Centralizer
Product No. 9115



"H-20" Hinge-Lok
Casing Centralizer
Product No. 9112



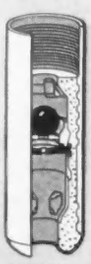
"H-25" Hinge-Lok
Casing Centralizer
Product No. 9113



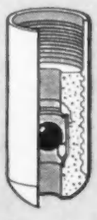
Hinge-Lok Rigid
Casing Centralizer
Product No. 9133

Triplex Cementing Shoe Product No. 1363

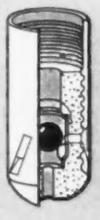
Differential
Fill-Up Shoe
Product No. 1081



Flexiflow
Fill-Up Shoe
Product No. 160

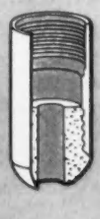


Cement
Float Shoe
Product No. 100



Cement Wash-Down
Whirler Float Shoe
Product No. 120

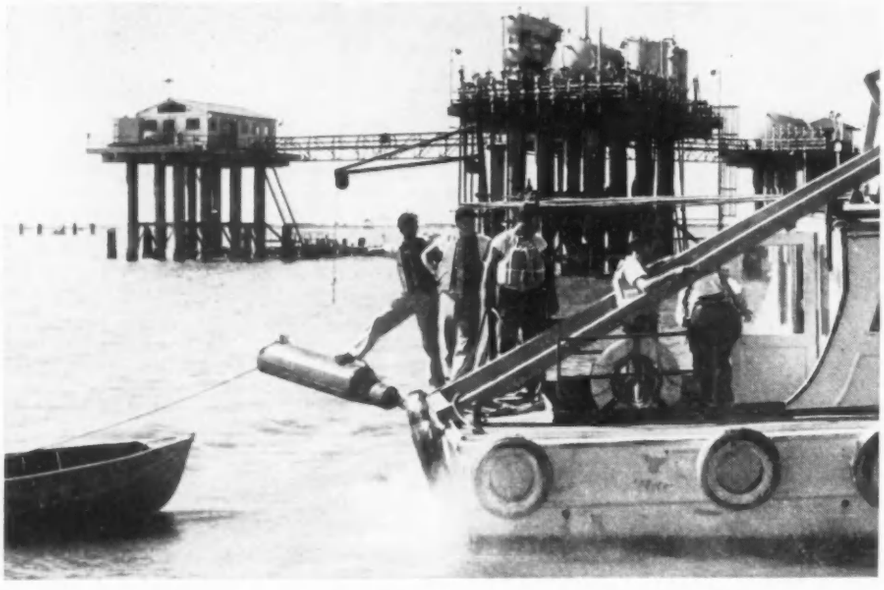
Cement
Bull Plug Shoe
Product No. 103



Cement Guide Shoe
Product No. 102

Your industry at work

A monthly roundup of items of interest about people, companies and associations



Man-Made 'Fish' Locates Buried Flowlines

Members of a Shell Oil Company land survey party prepare to lower a newly developed undersea buried metal locator near a production platform a mile off the Louisiana coast in the Gulf of Mexico. The locator, nicknamed a "fish," is used primarily to spot buried flowlines near prospective drilling sites. Noted for its ability to reveal accurately the depth of buried undersea flowlines of known size to within 3 to 6 inches, the locator was designed in Houston by Shell Development Company scientists.

Tidewater Oil Company Creates New Division

Tidewater Oil Company has formed a new operating division to contain its growing foreign exploration and production activities.

The new division will direct Tidewater's exploration and production work in all foreign countries with the exception of the Iranian Consortium in Iran, and operations in Saskatchewan, Canada.

General manager of the new division is Henry H. Neel, who headed a foreign exploration and production department before the formation of the company division. Neel has named Robert Dyke division exploration manager and John P. McCabe to the post of division production manager. A full management staff is planned for the division, and other executive appointments are expected to be announced in the near future.

Examining core sample from Turkey are executives of Tidewater Oil Company's new foreign exploration and production division, are Henry H. Neel (left), general manager, and Robert Dyke, exploration manager.

Petroleum Investments, Inc., Is Newly Formed Oil Firm

Petroleum Investments, Inc., has been formed in Shreveport, La., by a group of prominent oil operators.

Charles W. Glasscock, formerly of Glasscock Drilling Corporation, is chairman of the board; George J. Despot is president; Charles O. Hardey of the Hardey Company, is vice president, and O. P. Avinger, Jr., a partner in the certified public accounting firm of Heard, McElroy and Vestal, is secretary-treasurer.

Directors include: H. L. Kirkpatrick, Kirkpatrick and Associates; B. A. Hardey, a former president of the Independent Petroleum Association of America; George Despot and Robert A. Stacy, independent oil operators. Associated with the firm as consultants are: Hobson Mann, Oklahoma City, and O. G. McDowell, El Dorado, Ark., petroleum engineers, and Camille Despot, Houston geologist.

These guys have it rough!

From the Dec. 10, 1959, Albany, Ky., *Clinton County News:* "Oil men have started for the Knox (dolomite) in Clinton and Wayne counties at about 12 locations this year, but only three of them have been able to hit it without hitting a good well before they got there . . ." Some people just don't live right!

White Eagle Oil Merges With Rotary Engineering

Announcement was made by W. H. Helmerich, president of White Eagle International Oil Co., Tulsa, and Olin R. Prather, president of Rotary Engineering Co., Midland, Texas, of the merger of the two companies which was effective December 23. The combined operation will have assets exceeding $4 million in book value and annual revenues over $1 million.

Rotary Engineering will become a wholly owned subsidiary of White Eagle International in exchange for 987,000 shares of White Eagle International common stock but will continue to operate with its present name and organization.

Mobil Oil Affiliate Acquires Acreage in French Sahara

Mobil International Oil Company recently disclosed that one of its affiliates has signed a preliminary agreement with a French company, Compagnie d'Exploration Petroliers (CEP) and associated companies for a 25 percent interest in petroleum rights to approximately 8 million acres in the French Sahara.

The petroleum rights area is located along the Libyan border of the Sahara, in the Department of the Oases, between the Edjele and Hassi Messaoud oil producing areas.

Esso Foundation Reports Science Grants of $485,000

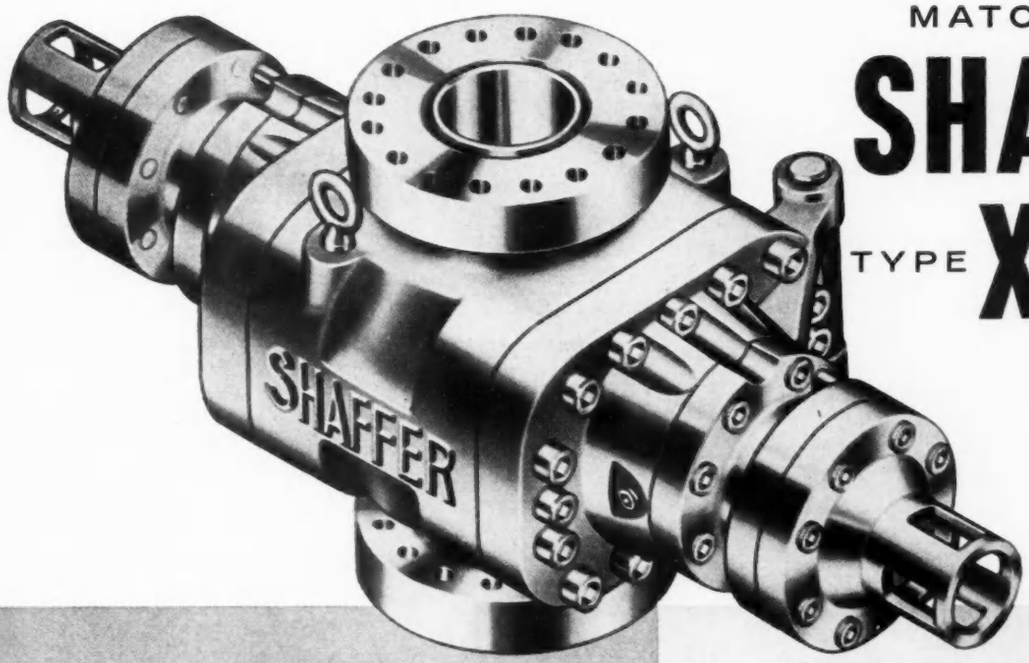
Grants totaling $485,000 to stimulate and improve science teaching at all educational levels were announced recently by the Esso Education Foundation. Fifty-four colleges and universities and six special projects in 25 states share in the grants.

The program, established in 1957, was one of the seventy-fifth anniversary activities of Standard Oil Company (New Jersey).

NOTHING in Blowout Preventers

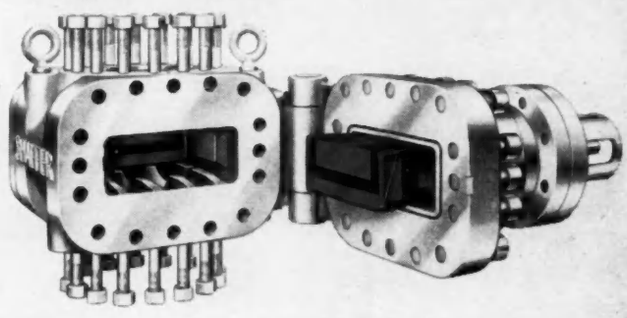
MATCHES THE

SHAFFER TYPE XHP



THERE'S FAR MORE to building a high pressure blowout preventer than just meeting a pressure rating. But if pressure rating is your first consideration, take a look at the kind of *extra high* pressures the Type XHP can handle . . .

- **7-1/16" Bore Size—22,500 PSI Test Pressure, 15,000 PSI Working Pressure!**
- **9" and 11" Bore Sizes—15,000 PSI Test Pressure, 10,000 PSI Working Pressure!**



But That's Only Part of the XHP Story.
Although it has an extra high pressure rating, the Type XHP is not clumsy to service nor cluttered in its design.

TO CHANGE RAMS or service the ram compartment you simply unbolt and swing the end doors open. And there's the ram on one side for easy access—the open ram compartment on the other side for checking or service.

Best of all, you don't break hydraulic lines or lose hydraulic fluid each time you open the XHP. Hydraulic lines are built into the body—*and the hinge pins*—for leak-tight operation whether the door is open or closed.

AND, OF COURSE, **the Type XHP has such other Shaffer advantages as QUICK-DRAINING RAM COMPARTMENTS, with the rams traveling on guide ribs high above any mud or sand that may collect in the compartment bottoms . . . and COMPLETELY ENCLOSED DESIGN with no exposed operating parts to become jammed or damaged by timbers or objects falling into the cellar.**

COMPARE **feature by feature and you'll find that nothing on the market equals the Type XHP for high pressure work combined with operating dependability and simple maintenance.**

36 years OF OIL TOOL LEADERSHIP

SHAFFER

HIGH PRESSURE DRILLING AND CONTROL EQUIPMENT • FISHING TOOLS THAT EXCEL

SHAFFER TOOL WORKS, Brea, California • California Service Shops: Santa Fe Springs and Taft
HOUSTON, TEXAS, 6006 Navigation Blvd. • ODESSA, TEXAS, 1925 West Second Street
OKLAHOMA CITY, OKLAHOMA, Shaffer Tool Works, 6201 South Shields Boulevard
FARMINGTON, NEW MEXICO, Shaffer Tool Works, Post Office Box 546
CASPER, WYOMING, Shaffer Tool Works, Post Office Box 1788
HOUMA, LOUISIANA, Shaffer Tool Works, Post Office Box 827
EXPORT SALES OFFICE: Shaffer Tool Works, 500 Fifth Avenue, New York, N. Y., U.S.A.

THIS FREE 12-PAGE BROCHURE gives you complete facts and figures on the Shaffer Type XHP. Write or phone your nearby Shaffer representative for your free copy!

Men in the industry

D. C. Hemsell has become assistant to **C. O. Stark,** vice president, land and geology, as a result of several promotions announced by **Phillips Petroleum Company.** Other promotions include: **W. B. Weeks** who succeeds Hemsell as department manager; **E. Van den Bark,** Southwest Regional manager, succeeding Weeks as assistant department manager; and **A. J. Hintze,** director of exploration, who continues in his present position and in addition will assist in departmental management duties.

D. C. Hemsell

W. B. Weeks

Homer Z. Martin has been appointed to the executive post of coordinator of petroleum process research in **Esso Research and Engineering Company.**

Clark M. Shimeall, formerly chief geologist for **The Ohio Oil Company of Guatemala,** has been named exploration manager succeeding the retired **Arthur H. Petsch.**

W. A. McKenna, Jr., has been appointed division manager at Denver for **South Texas Development Company** and **Wytex Oil Company. J. C. Brandy,** formerly of Albuquerque, N. M., also moved to Denver, succeeding the retired **J. L. Jones.**

Dr. Hollis D. Hedberg has been awarded a professorship in geology at **Princeton University.** He is withdrawing from administrative work with **Gulf Oil Corporation,** but will remain as before, vice president of Gulf Oil for exploration. Hedberg was also elected president of the **Geological Society of America** in November 1959.

A. J. Hintze

E. Van den Bark

PERFORATE TUBING IN THE WELL

KINLEY TUBING PERFORATOR

M. M. Kinley Company Licensees

ABILENE, TEXAS—Hudson-Eads, Inc....OR 2-5331
ANACO, ANZOATEGUI, VENEZUELA
Anzoategui Wire-Line Service, C. A.
BAY CITY, TEXAS—J. P. Graham.....CI 5-4526
BEAUMONT, TEXAS
Assoc. Eng. & Eqpt., Inc. TE 5-7046, ZF 8-2023
CABIMAS, ZULIA, VENEZUELA
Wireline Engineers, S. A.
CASPER, WYOMING—C. A. White.....3-5264
CORPUS CHRISTI, TEXAS—Tolle, Inc...TE 5-5367
FARMINGTON, NEW MEXICO
B & R Service, Inc.....DA 5-2393
FORT MORGAN, COLORADO—C. A. White 919
GLENDIVE, MONTANA—C. A. White...EM 5-3833
HOBBS, NEW MEXICO
Horne Well Service Co.....3-5396
HOUMA, LOUISIANA—Cameo, Inc.....7330
HOUSTON, TEXAS
Assoc. Eng. & Eqpt., Inc.....CA 5-1103
HOUSTON, TEXAS
Mid-Western Well Ser. Co.....RE 4-4262
HOUSTON, TEXAS
Long Line Production Co.....GR 3-5739
LAFAYETTE, LOUISIANA
Assoc. Eng. & Eqpt., Inc.....CE 5-6770
Cameo, Inc.....CE 5-3124
LIBERAL, KANSAS—Rainbo Service...Main 4-3598
MIDLAND, TEXAS
Luccous Service & Eqpt. Co.....MU 2-1631
HOUMA, LOUISIANA
Assoc. Eng. & Equip. Inc.....UP 2-0347
ODESSA, TEXAS
Cameo Wire Line Service, Inc.....FE 2-6497
OKLAHOMA CITY, OKLAHOMA
Rainbo Service Co.....ME 4-2131, ME 4-0105
PETTUS, TEXAS
Eddie Jones Eng. Co., Pettus 16, Beeville, FL 8-1218
SHREVEPORT, LOUISIANA—Cameo, Inc....8-3615
VICTORIA, TEXAS—Cameo, Inc.....HI 3-9521
WHITTIER, CALIFORNIA
Kline Wire Line Co.....OX 3-2731
WICHITA FALLS, TEXAS—Hudson-Eads, Inc.
322-8584, 322-1792, 767-8727, 723-4690, 767-3793

F. E. McPhillips

E. M. Benson, Jr.

F. E. McPhillips has been appointed to the newly created position of assistant general manager of the Production Department of **Richfield Oil Corporation.** Also, **E. M. Benson, Jr.,** has assumed McPhillips' former position as manager of the Land & Lease Division.

Roy B. Middleton has been appointed advertising coordinator of **DX Sunray Oil Co.**

Newton B. Dismukes has been made production manager for **Mobil International Oil Company's** Producing Department. He succeeds **G. R. Lucie-Smith,** who has been appointed general manager in Libya for **Mobil Oil of Canada, Ltd.**

Gerald G. Loucks, a district exploration geologist in Canada, has been transferred to the **Kerr-McGee Oil Industries, Inc.,** Southern Rocky Mountain region office in Denver. Other transferees include: **Jon Palmer,** formerly junior geologist in Denver, to the Oklahoma City office; **Harold Thurman,** geologist, has transferred from Oklahoma City to the Southern Division office in New Orleans; and **Joe Hull,** formerly staff geologist in Oklahoma City, has transferred to the Canadian Division office at Calgary, Alta.

Plato Malozemoff has been elected to the Advisory Board on International Business by the **Chemical Bank New York Trust Company.** He is a director of **Continental Oil Company, Newmont Oil Company, Canadian Export Gas & Oil Ltd.,** and many other firms in Canada.

Harold D. Hoopman, operations manager of **The Ohio Oil Company of Guatemala,** has been appointed resident manager succeeding the late **J. Patrick D'Artois.**

H. D. Hoopman

E. N. Spiars

Early N. Spiars has been added to the staff of **Pat Casey & Associates,** oil and gas management firm, as a petroleum engineer and field representative.

E. L. (Gene) Maxwell, Rocky Mountain Regional exploration manager at Denver for **Lion Oil Company,** a **Division of Monsanto Chemical Company,** has been promoted to director of Domestic Exploration. Also, **A. L. Bergren, Jr.,** previously regional geologist for the Rocky Mountain Region, has been promoted to Rocky Mountain Regional exploration manager. **T. W. (Wes) Lins,** previously assistant regional geologist for the same area, has been appointed regional geologist and will direct geological activity for the region from his Denver offices.

Ernest P. Zseleczky has been promoted as head of a section in the computing center of **Esso Research and Engineering Company.** He will head the unit's operations section.

Jeff Watts has joined the staff of **Buttes Gas & Oil Company** as chief petroleum engineer and assistant general manager.

C. F. Baird has been appointed assistant treasurer of **Standard Oil Company (New Jersey).**

Alexander Clark of Calgara, Alta., has been appointed to the office of president of **The Calgary & Edmonton Corporation Limited.**

Dr. Scott W. Walker, assistant manager of research for **Pan American Petroleum Corp.,** and for 6 years a faculty member

Men in the industry

at Massachusetts Institute of Technology, has been named dean of the College of Petroleum Sciences and Engineering at the **University of Tulsa.**

Robert J. Bradley has been elected chairman of the board and chief executive officer of **Production Properties, Inc.,** Dallas. **Mac D. Oliver** succeeds **Bradley** as president. **Virgil B. Harris** was elected to the newly created post of executive vice president.

Wm. J. Zeman

H. D. Turner

H. K. Hudson

L. G. Minter

Wm. J. Zeman has been promoted to general attorney by **Phillips Petroleum Company,** succeeding **Harry D. Turner** who has become a special counsel in Tulsa. **H. K. Hudson** has been named counsel on special assignment, and **Lloyd G. Minter** has become assistant general attorney.

Norman D. Farrell has been advanced to the newly created position of assistant controller of **Helmerich & Payne, Inc.**

Robert B. Woodin has been appointed director of Financial and Public Relations by **Delhi-Taylor Oil Corporation.** Woodin will report directly to **C. H. Hobbs,** executive assistant to the president.

George G. Thomson, Jr., has been elected vice president of **Asiatic Petroleum Corporation** and will be responsible for public and government relations.

Deaths

A. L. Burns, president of **Gulf Printing Company** and a director of **Gulf Publishing Company,** was killed in the crash of a private plane near Eagle Lake, Texas, December 31. Burns joined Gulf Publishing Company in 1920 and was vice president and general manager until 1956 when he retired from the Publishing company to devote his full time to Gulf Printing Company.

W. O. (Sonny) Calvert, former overseas representative for several Houston based oil field goods manufacturers, died November 28 in Houston. He was 53 years old. He had served in Europe and the Middle East for **Mission Manufacturing Co.** and **Thornhill-Craver Co.**

Harry R. Miller, labor relations manager for **Standard Oil Company of California,** died of a heart attack while on a recent business trip to Perth Amboy, N.J. He was 53.

J. Patrick D'Artois, 51, resident manager of **The Ohio Oil Company of Guatemala,** died in October at Guatemala City, Guatemala, of complications following a heart attack.

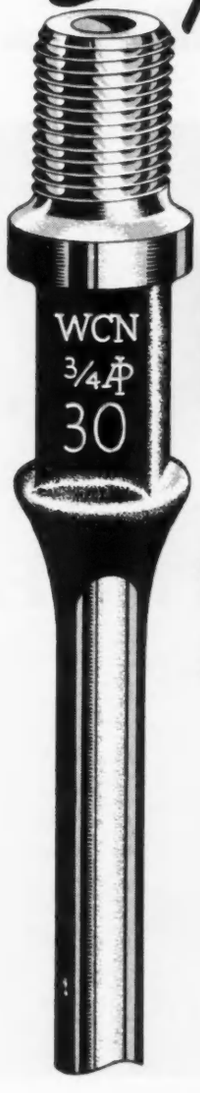
Roy Ellis Callahan, 63, traffic manager for **Sinclair Oil and Gas Co.,** Tulsa, died October 28. He had worked for Sinclair for 36 years.

K. A. Beede, general superintendent of plants in the New York Region for **American Oil Company,** died October 23 following a brief illness.

W. R. (Bill) Boyd, prominent oil man and a past president of the American Petroleum Institute, died at his home in Teague, Texas, November 6.

Experience

BUILDS A BETTER SUCKER ROD



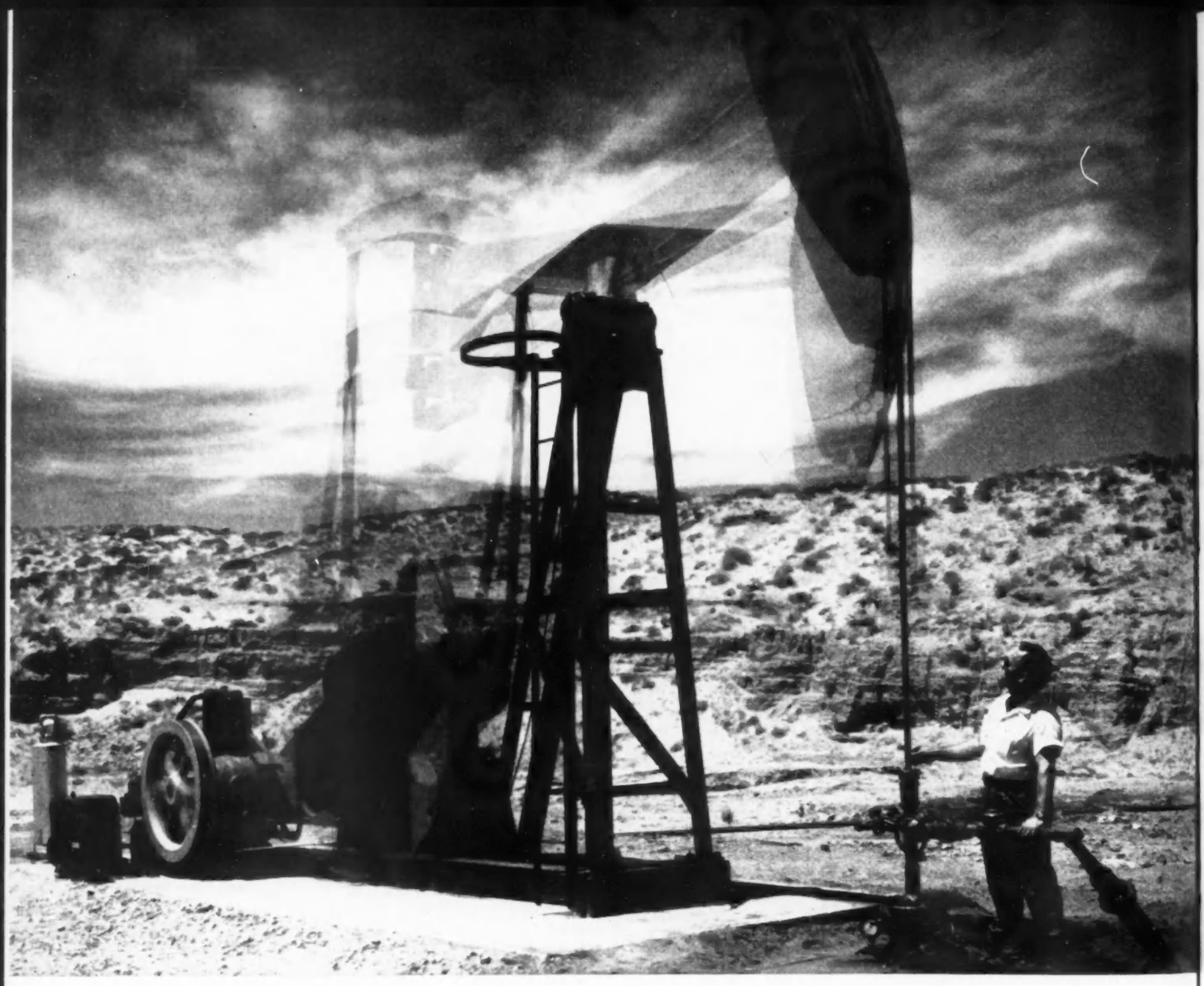
W.C. NORRIS SUCKER RODS

Write for complete Sucker Rod Bulletin

W. C. NORRIS, MANUFACTURER
DIVISION OF DOVER CORPORATION
P. O. BOX 1739 • TULSA, OKLAHOMA
BRANCHES: Great Bend, Kansas; Corpus Christi, Houston, Kilgore, Odessa, Wichita Falls, Texas; Oklahoma City, Oklahoma; Salem, Illinois; Casper, Wyoming; Farmington, New Mexico; Edmonton, Alberta, Canada.

NORRIS QUALITY
SUCKER RODS
POLISHED RODS · COUPLINGS

Buy From Your NORRIS Distributor



Not a Quiver in the Polished Rod

Bethlehem units can be lined-up quickly, accurately —and will *stay* in alignment

Correct alignment over a hole is never a problem when you have a Bethlehem pumping unit on the job. Critical align points are center punchmarked so that accurate line-of-sight placement of any Bethlehem unit can be made quickly and easily.

And top-quality construction—a tradition maintained in all Bethlehem products throughout every change to better design—assures every producer that his Bethlehem units will hold their alignment, year in and year out.

What do you need in a pumping unit? Bethlehem units range in capacity from 6,000 to 640,000 in.-lb torque; will handle polished-rod loads from 2,000 to 33,000 lb. Strokes range from 16 up to 168 in. And every unit features these advantages:

- Portability, if desired.
- Elevated motor power assembly.
- Hydraulically removable wrist pin, with self-aligning spherical roller bearings.
- Full roller-bearing gear reducer with forged-steel gears; flood lubrication; settling chamber.
- Saddle bearing of one-piece construction; prepacked, if desired.

Whatever your needs in pumping units, you need ask no further than our nearest office or store.

BETHLEHEM STEEL COMPANY
Supply Division
General Offices and Export Dept.: 21 E. Second St., Tulsa, Okla.
Canadian Distributor: Bethlehem Supply Company of Canada, Ltd., Calgary, Alberta, Canada

BETHLEHEM STEEL • SUPPLY DIVISION

WHO'S MEETING WHERE

Feb. 8	Canadian Petroleum Association, Annual Meeting, Alberta Division, Palliser Hotel, Calgary, Alta.
8–10	AAPG, Rocky Mountain Section, Tenth Annual Meeting, Billings, Mont.
9	Advanced Petroleum Engineering Seminar, University of Oklahoma, Norman.
14–18	AIME, Annual Meeting, Statler Hotel, New York City.
24–25	Wisconsin Petroleum Association, Thirty-fourth Annual Convention and Exhibit, Schroeder Hotel, Milwaukee
24–26	NACE, Eleventh Annual Corrosion Short Course, Mayo Hotel, Tulsa.
26	Ohio Oil and Gas Association, Winter Meeting, Deshler-Hilton Hotel, Columbus.
Mar. 2– 4	API, Division of Production, Southwestern District Meeting, Statler-Hilton Hotel, Dallas.
7	Canadian Petroleum Association, Annual General Meeting, Palliser Hotel, Calgary, Alta.
14–18	NACE, 16th Annual Meeting, Memorial Auditorium, Dallas.
16–18	API, Division of Production, Southern District Meeting, Hilton Hotel, San Antonio, Texas.
23	Oil Trade Association of New York Meeting, Waldorf-Astoria Hotel, New York City.
30 thru Apr. 1	API, Division of Production, Mid-Continent District Meeting, Broadview Hotel, Wichita, Kan.
April 7– 8	Rocky Mountain Oil & Gas Association Mid-Year Meeting, Newhouse Hotel, Salt Lake City, Utah.
12–14	Thirty-second PIEA-PESA Conference and Exhibition, Municipal Auditorium, Kansas City, Mo.
20–22	API, Division of Production, Rocky Mountain District Meeting, Gladstone, Henning and Townsend Hotels, Casper, Wyo.
20–22	NPA, Semi-annual Meeting, Hotel Cleveland, Cleveland.
21–22	Seventh Annual West Texas Oil Lifting Short Course, Texas Technological College, Lubbock.
21–23	Permian Basin Section SEPM, Annual Meeting and Field Trip, Abilene, Texas.
24–26	IPA of America, Mid-Year Meeting, Denver-Hilton Hotel, Denver.
25–28	AAPG-SEPM, Annual Meeting, Chalfonte-Haddon Hall, Atlantic City, N.J.
25– thru May 6	Advanced Drilling Engineering Course, Texas A. & M. College, College Station, Texas.
May 1– 4	API, Division of Transportation, Tanker Conference. Seaview Country Club, Absecon, N.J.
2– 3	SAE of AIME, Wichita Falls, Texas.
2– 4	AIME, North Texas Secondary Recovery Symposium (Biennial), Wichita Falls, Texas.
5– 6	AIME, Rocky Mountain Petroleum Sections, Annual Joint Meeting, Calgary, Alb., Canada.
12–13	API Division of Production, Pacific Coast District Meeting, Biltmore Hotel, Los Angeles.
25–28	AAPG, Western Canada Regional Meeting, Banff Springs Hotel, Banff, Alberta.
June 5–10	SAE, Summer Meeting, Edgewater Beach Hotel, Chicago.
12–17	API Division of Production, Mid-year Committee Conference, Sheraton-Dallas Hotel, Dallas.
28–30	API Division of Production, Eastern District Meeting, Greenbriar Hotel, White Sulphur Springs, W. Va.

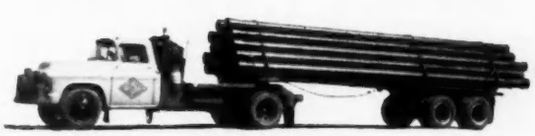
Nomads' Chapter monthly meeting: Los Angeles, second Wednesday, Hotel Biltmore, Wallace A. Sawdon, Secretary. Houston, second Monday, Ye Old College Inn, Harry E. Estes, Secretary. Dallas-Fort Worth, first Monday, Greater Dallas Club, Hank Davis, Secretary. Tulsa, Hotel Tulsa, Gilbert Swift, Secretary. New York, first Monday, Hotel Biltmore, Jesse E. Hickman, Secretary.

Congrats and $25 for this quip to CAROLYN KENEDY, Bells Wells Oil Company, Box 269, Miami, Oklahoma.

When it comes to shapeliness . . . Lone Star pipe proportions are right! All dimensions and qualities are strictly API specifications.

Lone Star Steel . . . America's most modern pipe plant . . . is Joe Roughneck's solid source of supply. Right here in the center of the oil country . . . quick availability of Lone Star pipe is a terrific convenience.

Neighbor, wherever you are, specify Lone Star and we both get a good deal.



© 1956 Lone Star Steel Company

Lone Star STEEL COMPANY

EXECUTIVE—SALES OFFICES
W. Mockingbird Lane at Roper • P. O. Box 12226 • Dallas, Texas
DISTRICT SALES OFFICES
912 Republic National Bank Building, Dallas, Texas
Houston, Texas | Midland, Texas | Tulsa, Oklahoma

For more data on advertised products, use Readers' Service Cards, last page.

Associations

Prominent Geologists Receive GSA's Highest Awards

Sir Edward Bullard, Dr. Adolph Knopf and Dr. Jack L. Hough (left to right) were awarded the Geological Society of America's highest honors before an overflow crowd at the annual dinner in Pittsburgh. The Penrose Medalist awardee was Dr. Adolph Knopf, noted geologist and professor at Stanford University. He has made valuable contributions to his profession through his studies of the age of the earth, the origin of vein deposits and the nature of volcanic rocks. Dr. Knopf was president of the Society in 1945. Sir Edward Bullard of Cambridge, England, was awarded the Arthur L. Day Medal for his many significant contributions to geology through physics. These include the development of instruments used to solve problems relating to the earth, such as its structure and its gravitational and magnetic fields. The recipient of the Kirk Bryan Award, Dr. Hough, won the award for his study of fresh water oceanography conducted in the Great Lakes. The awards dinner was the main event of the society's seventy-second annual convention.

Permian Basin Society Elects Clark President

John E. Clark, Union Oil Company, has been elected president of the Permian Basin Geophysical Society. E. E. Fickenger, Continental Oil Co., was elected first vice president; B. H. Hinton, of Ralph Lowe firm, second vice president; L. M. Scofield, Burton Exploration Co., secretary, and S. T. Miller, Tennessee Gas Transmission Company, treasurer.

Billings, Mont., Geologists To Host Annual Convention

The Billings, Mont., geologists will play host to more than 1,000 geologists from throughout the Rocky Mountain area when they convene in Billings February 7-10, for the annual Rocky Mountain Section meeting of the American Association of Petroleum Geologists.

James O. Staggs, division geologist for McAlester Fuel, Billings, is general chairman for the meeting. The theme for the annual event is "Future Exploration After a Decade of Progress." Approximately 33 technical papers will be presented.

SEG Announces Two Honorary Memberships

Dr. W. T. Born and Dr. Louis Slichter have been awarded honorary life memberships to the Society of Exploration Geophysicists.

Born received his award for service to the society and scientific contributions to the art of geophysics. Slichter, director of the Institute of Geophysics at the University of California at Los Angeles, received his award for his contribution to mining geophysics and his activity in the training of younger geophysicists through his teaching career.

A third award was made post-humously to Frank Rieber, most of whose career was in California. As early as 1934 he developed a new technique revolutionary for that period, of recording seismograph records used in oil exploration in a reproducible form.

Ohio Oil & Gas Association Names Officers for New Year

The Ohio Oil and Gas Association has named officers to direct the organization in 1960. R. L. (Dick) Vockel, head of the Waverly Oil Works, is the new president, succeeding J. W. Straken.

R. C. McConnell, Clinton Oil Company, was elected vice president; S. A. Anderson, National Gas and Oil Corporation, treasurer; and Ira M. Korst, executive secretary.

Kansas Governor Elected Chairman of IOCC for 1960

Governor George Doking of Kansas was elected chairman of the Interstate Oil Compact Commission in the concluding session of the organization's annual meeting recently. He succeeds Governor J. Hugo Aronson of Montana for the one-year term.

Others elected were Warwick M. Downing, chairman of the Colorado Oil and Gas Conservation Commission, first vice chairman, and Miss Genevieve Blatt, Pennsylvania Secretary of Internal Affairs, second vice chairman. Lawrence R. Alley of Oklahoma City was re-elected executive secretary.

Governors or their representatives from the following states were elected to the executive committee: Arkansas, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, North Dakota, Alabama and Kentucky.

The 1960 mid-year meeting of the commission will be held on June 15-17 in Detroit. The annual meeting will be held on December 5-7 in Pheonix, Ariz.

Panhandle Chapter of API Elects 1960 Officers

The Panhandle Chapter of the American Petroleum Institute Division of Production has named officers for 1960. The officers are: Griswold Rogers, Pan American Petroleum Corporation, chairman; Max Bollick, Cities Service, first vice chairman; Jos. Kenworthy, Kewanee Oil Co., second vice chairman; Paul Wiley, Texaco Inc., third vice chairman; Martin Ludeman, West Pampa Repressuring Group, secretary-treasurer, and Frank Storm, retiring chairman, as chairman of the executive committee.

South Texas Geologists Elect Officers for 1960

Officers for 1960 have been elected by the South Texas Geological Society. Named to serve for one year are: John S. Rives, George H. Coates, Independent, president; Roy H. Guess, Newman Brothers Drilling Company, vice president; Charles E. Kimmell, Bright and Schiff, secretary; Wilford L. Stapp, Phillips Drilling Company, treasurer. Robert L. Begeman, Tobin & Begeman, and James G. Joyce, Standard Oil Company of Texas, were elected to the executive committee.

Denver Section of AIME Installs New Directors

John Ferry, petroleum engineer, Denver-U.S. National Bank, was recently elected chairman of the Denver Section of the Society of Petroleum Engineers of AIME. Other officers are: Willard Bauman, division petroleum engineer, Gulf Oil Company, director; E. N. Dunlap, division engineer, Texaco Inc., director, James Roe, Rocky Mountain Division manager, Lufkin Foundry and Machine, secretary-treasurer; L. B. Curtis, Rocky Mountain Regional engineer, Continental Oil Company, first vice chairman, and James Taylor, president TWH Drilling Company, second vice chairman.

John Ferry

The Denver Section will host the 1960 annual meeting of the Society in October in Denver.

GCAGC Elects M. F. Kirby New President for 1960

M. F. Kirby, Gulf Oil Company, Jackson, Miss., was recently elected president for 1960 of the Gulf Coast Association of Geological Societies. Other officers for 1960, elected at an executive meeting in Houston, are Dodd N. Osburn, Union Producing Company, New Orleans, vice president; William W. Woolfolk, Ohio Oil Company, San Antonio, secretary; and E. G. Jefferys, consultant, Jackson, Miss., treasurer.

The group will hold its 1960 convention at Biloxi, Miss., October 19-21.

Suppliers' notes

D. W. McCain

T. G. Gilbert

Donald W. McCain has been named Canadian manager for **Electro-Technical Labs., Division of Mandrel Industries, Inc.**, and will make his office in Calgary, Alb. McCain succeeds **Thomas G. Gilbert** who has transferred to Mandrel's Houston Division in a marketing management capacity.

Schley Babin has been transferred from Tulsa to Houston as head of the new office recently opened there by **Halliburton Oil Well Cementing Company.** Also, **Bill Taylor** has been named as head of the new Dallas office opened there by Halliburton.

D. Brian Wheeler has been appointed director of sales engineering for **White Truck Division** of **The White Motor Company.** Wheeler replaces **William L. Peterson,** new manager of the White Truck sales, parts and service branch in Philadelphia.

Howard W. Brandt, general manager of **The New York Air Brake Company's Hydreco Division** in Kalamazoo, Mich., has been promoted to vice president of the company. Brandt will continue to direct activities of the Hydreco Division.

L. W. Jones has been appointed sales manager Foreign Operations for **Baroid Division** of **National Lead Company.** Jones will represent Baroid's overseas affiliates and the Baroid Division's foreign operations.

Gil A. Lastrapes, Jr., has been named production valve salesman representative at Harvey, La., for the **Grove Valve and Regulator Company.**

Jim Riseden has been appointed sales engineer for the **Service Foundry Division** of **Avondale Marine Ways, Inc.,** in New Orleans. Riseden was formerly district sales manager for the J. B. Beaird Company of Shreveport, La.

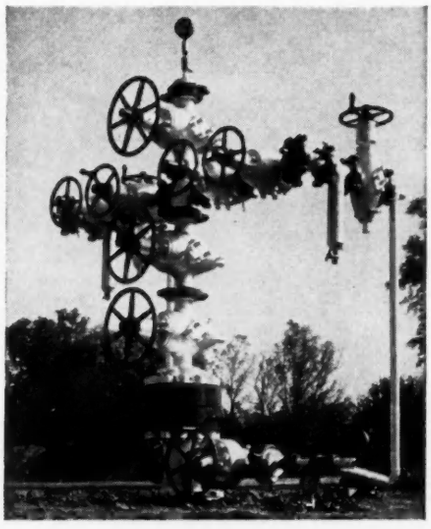
J. A. MacIntire has been promoted to the position of general sales manager of **Republic Rubber Division** of **Lee Rubber & Tire Corporation.** MacIntire will fill the office made vacant by the recent death of **C. R. Conklin.**

G. R. Cain, Jones & Laughlin Supply Division, has been appointed salesman for the company at Kermit, Texas. He was previously at Borger, Texas.

John T. Orton, sales division manager for Northern and South America for

W-K-M Receives National Safety Award

W-K-M Division of ACF Industries, Incorporated, was presented the National Safety Council's Award of Merit for its excellent safety record of its disabling injury-free period of 1,551,590 man-hours from October 1, 1958, to July 12, 1959. J. U. Parker (left), executive member of the National Safety Council and chief safety engineer for Humble Oil & Refining Company, presented the award of merit to Henry C. Tooley (center), vice president of manufacturing for W-K-M, and Jim Skipton, W-K-M safety supervisor. The award is given only where a safety record has been established according to rigid requirements laid down by the National Safety Council.



GRAY

Complete Well Control For Complete Safety

Gray Well Head Assemblies are designed, engineered and constructed to give you complete control of your well.

The result is complete safety from the casing head to the pressure gauge.

Design simplicity eliminates unnecessary weight, puts the metal at points of stress. Engineering provides maximum flexibility in positive, efficient handling of single or multiple zones in high, medium or low pressures at any depths.

That's why Gray Systems of Well Control give you *more strength with less weight . . . complete control with complete safety.*

For more information about Gray's Systems of Well Control, see the Gray Catalog in Composite Catalog or write

GRAY *Tool Company*

P. O. BOX 2291 HOUSTON, TEXAS
REpublic 4-1641

MAIL THIS COUPON TODAY

GRAY TOOL COMPANY
P. O. Box 2291 Houston, Texas

Please send me full details of the Gray Systems of Well Control.

Name_____

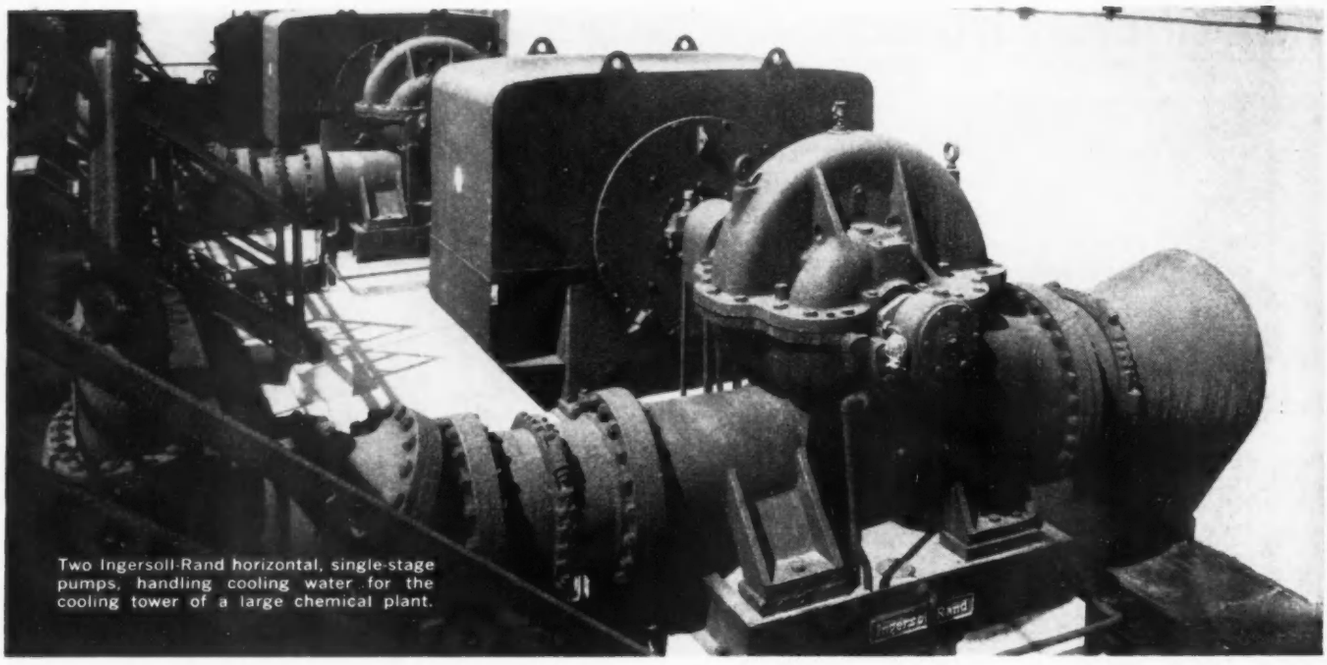
Company_____

Title_____

Address_____

City_____ State_____

5202



Two Ingersoll-Rand horizontal, single-stage pumps, handling cooling water for the cooling tower of a large chemical plant.

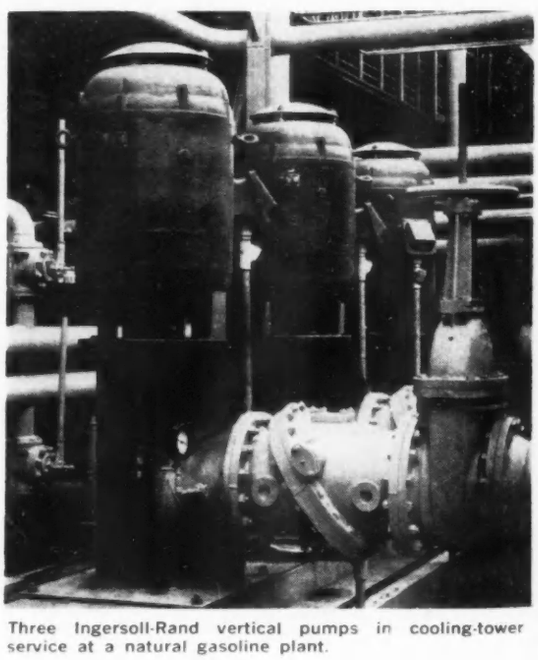
HORIZONTAL OR VERTICAL

I-R Cooling Tower Pumps
CUT COOLING COSTS

Whether the physical requirements of your cooling tower installation dictate the use of horizontal or vertical pumps, the *cost* of supplying cooling water depends on two basic factors.

1. The *efficiency* of the pump—which determines the power cost per month or year, to deliver the required pressure and capacity. Ingersoll-Rand pumps are designed and built for high efficiency – not just initially, but throughout years of continuous operation. Impeller and volute designs minimize internal resistance, and running clearances are liberal enough to permit *sustained* high efficiency year after year.
2. The pump *maintenance cost* – the money you have to spend to keep it in operating condition over a long period of time, plus the cost of any enforced shut-downs that might result. Here, the extra *dependability* of I-R pumps – proved on thousands of jobs all over the world – can mean important savings. I-R pumps are designed for easier maintenance and *less of it*.

Ingersoll-Rand manufactures a complete line of both horizontal and vertical pumps for cooling tower service. Ask your I-R engineer for the dollar-saving data on the type best suited to your needs.



Three Ingersoll-Rand vertical pumps in cooling-tower service at a natural gasoline plant.

A CENTURY 1860 – 1960 OF PUMP PROGRESS

Ingersoll-Rand

11 Broadway, New York 4, N. Y.

86A10

COMPRESSORS · GAS & DIESEL ENGINES · PUMPS · AIR & ELECTRIC TOOLS · CONDENSERS · VACUUM EQUIPMENT · ROCK DRILLS

Suppliers' notes

Reed Roller Bit Company, has been transferred to London. Orton replaces **T. C. (Ted) Lemcke** who has been reassigned to Reed's headquarters in Houston to assume new responsibilities.

Earl F. Snow

Earl F. Snow has been named materials manager of the **Baash-Ross Division of Joy Manufacturing Company.** Located at the home office in Houston, Snow is responsible for all production and material control, traffic and purchasing. Prior to joining the Baash-Ross-Division, Snow was with Reed Roller Bit Company.

C. W. (Bill) Floyd, Jr., has been appointed system division engineer of **Sargent Engineering Corporation, Petroleum Production Systems Division.**

Jay Hembree has joined the **Gulf Coast Machine & Supply Company** of Beaumont, Texas, as a member of the sales organization.

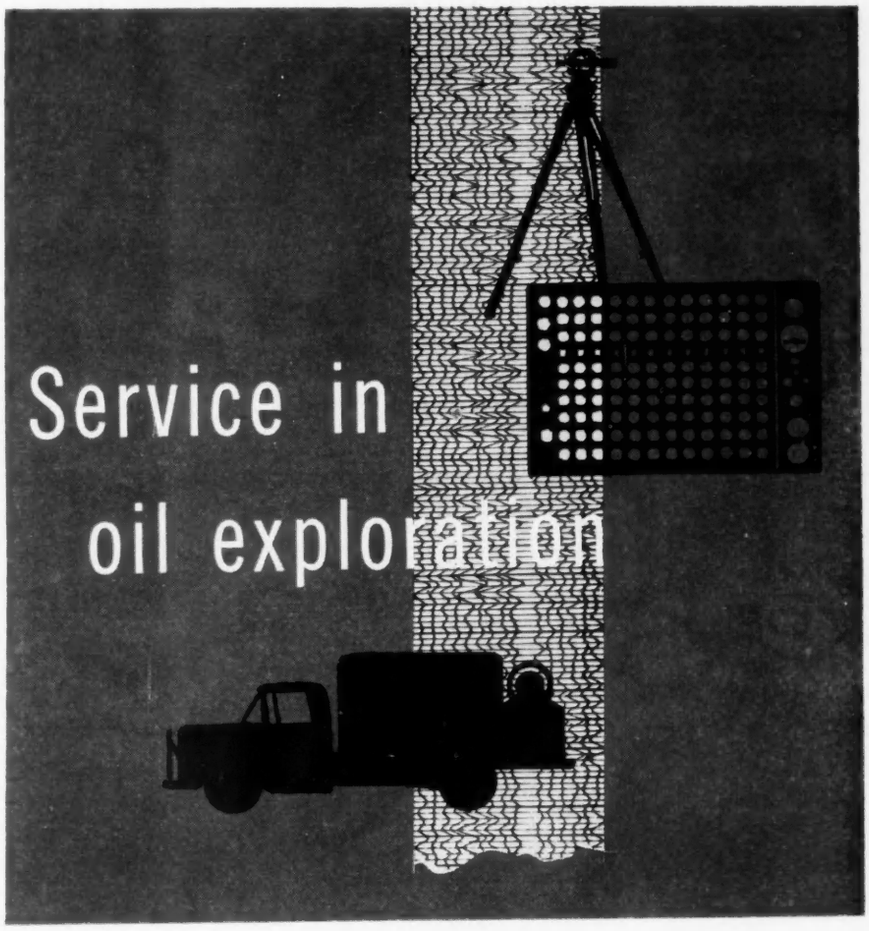
W. L. Haslam has been appointed manager, chemical and metal sales, San Francisco district, and **Alan Purchase** appointed manager, industrial sales, Los Angeles district for **Allis-Chalmers Manufacturing Company.**

H. R. Wells has been elected executive vice president of production and properties for **Milwhite Mud Sales Company of Houston.** Wells is also a director of Milwhite. Recent positions held by Wells include assistant to chief engineer of Mississippi River Fuel Corporation (parent company of Milwhite Mud Sales Company); vice president of Mobar Corporation (formerly production division of Milwhite); and vice president of Milwhite.

H. R. Wells

H. L. Kenagy, purchasing agent for the Kansas City works of **Sheffield Division** of **Armco Steel Corporation,** has been named director of purchases for Sheffield's three plants at Sand Springs, Kansas City and Houston. **J. A. Street,** manager of scrap purchases, was appointed assistant director of purchases for the three plants.

C. W. Moore has been named district sales manager for the Eastern Oklahoma district for **Jones & Laughlin Supply Division.** He replaces the late **A. A. Hopper.**



. . . YESTERDAY,

TODAY,

TOMORROW

We, at Petty, are proud of our contributions to the discovery of oil. We pledge ourselves to continued service to the oil industry with superior seismic crews and constant research in the development of newer and better techniques and equipment.

Petty

GEOPHYSICAL

ENGINEERING CO.

TRANSIT TOWER SAN ANTONIO, TEXAS CApitol 6-1393

Suppliers' notes

A. K. Simpson

A. K. Simpson, formerly general sales manager of Shaw-Petrie Ltd., and Clyde Tube Forgings Ltd., has been appointed commercial manager of **Woodfield Rochester Ltd.** Simpson will act as deputy to R. H. Corbett, director, in relations to the sales responsibilities.

William S. Lennard has been appointed manager of the drilling equipment sales in Los Angeles for **U.S. Steel's Oil Well Supply Division.**

Kenneth Palmer, formerly assistant to the Advertising manager of **The National Supply Company,** has been named to replace **Allen P. Colby** as manager. Colby has retired after 38 years with the company.

Charles R. Hook has resigned as chairman of the board of **Armco Steel Corporation.** The directors elected Hook honorary chairman. He will continue as a director of the company.

R. J. Mason

R. G. Stookey

T. L. McSwine

Thomas L. (Larry) McSwine has been promoted to director of marketing for **American Coldset Corporation. Robert J. Mason** was named manager of the Tool and Wheel Division, and **Royal G. Stookey** was appointed manager of manufacturing.

W. M. Burstall, superintendent of **Byron Jackson's** Oil Tool Plant 4, has been promoted to chief tool engineer, Methods and Routing Department. **Gale Smith** was appointed superintendent of BJ's Oil Tool Plant 1. In his new position, Smith will be responsible for all production operations of the plant.

G. W. Haase has been named manager of the new supply store at Kimball, Neb., for **The National Supply Company.** The new store is under the jurisdiction of **Luther M. Miller,** manager of the Colorado district.

Bowen Itco Purchases Kinzbach Tool Company

Bowen Itco, Inc., has announced the acquisition of all assets of the Kinzbach Tool Company, Inc. Both companies are headquartered in Houston and occupy adjoining property.

Fred N. Osmun, president of Bowen Itco made the announcement and stated that the addition of the Kinzbach line of oil field tools, whipstocks, mills, casing mills, stuffing boxes, tubing spiders and relief valves, complement Bowen Itco's own diversified line of oil field specialty tools for the fishing, drilling, production and wire line phases of the oil industry.

The Houston-based Kinzbach Company has 21 sales, service and warehouse facilities throughout the oil and gas producing areas in the United States, and 13 agents who are located in strategic oil areas overseas.

Bethlehem Completes Tulsa Plant Expansion Program

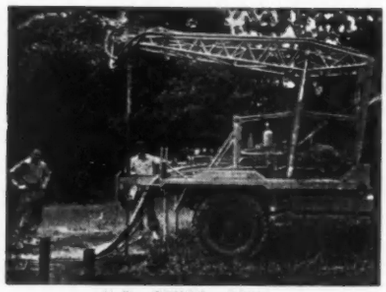
The Bethlehem Steel Company Supply Division recently completed the expansion of its Tulsa manufacturing facilities to include production of the Bethlehem line of duplex and triplex general purpose pumps.

The new facilities are expected to aug-

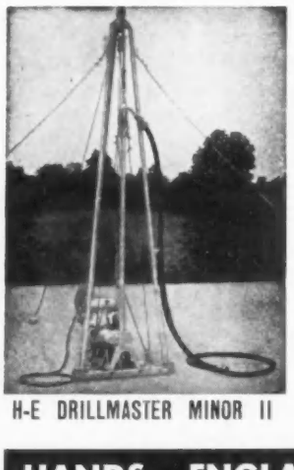
H-E GEOPHYSICAL EQUIPMENT

H-E manufacture a wide range of Geophysical supplies in addition to that illustrated including: loading poles, cable reels, winches, shooting trucks etc. Write for full details quoting ref.D/GL.

H-E TRACTOR DRILLMASTER



H-E TRUCK DRILL



H-E DRILLMASTER MINOR II

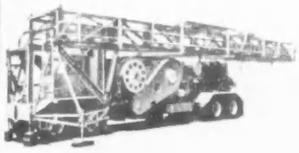
H-E RECORDING CAB

H-E WATER TRUCK

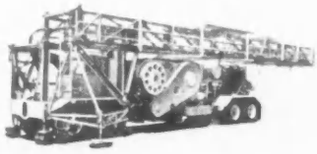
H-E BREAST REEL

HANDS - ENGLAND OILFIELD EQUIPMENT LTD
MANUFACTURERS OF GEOPHYSICAL SUPPLIES
LETCHWORTH HERTS ENGLAND TEL: 600 CABLES: OIL LETCHWORTH ENGLAND
Exclusive licensees in Western Germany: August Goettker Flachbotrungen, 20a Wathlingen Kreis Celle, West. Germany

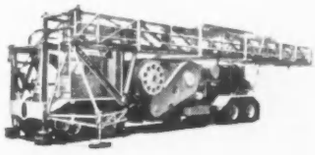
DRILLING



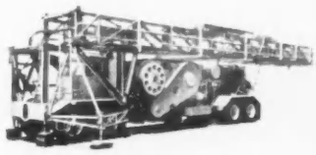
SERVICING

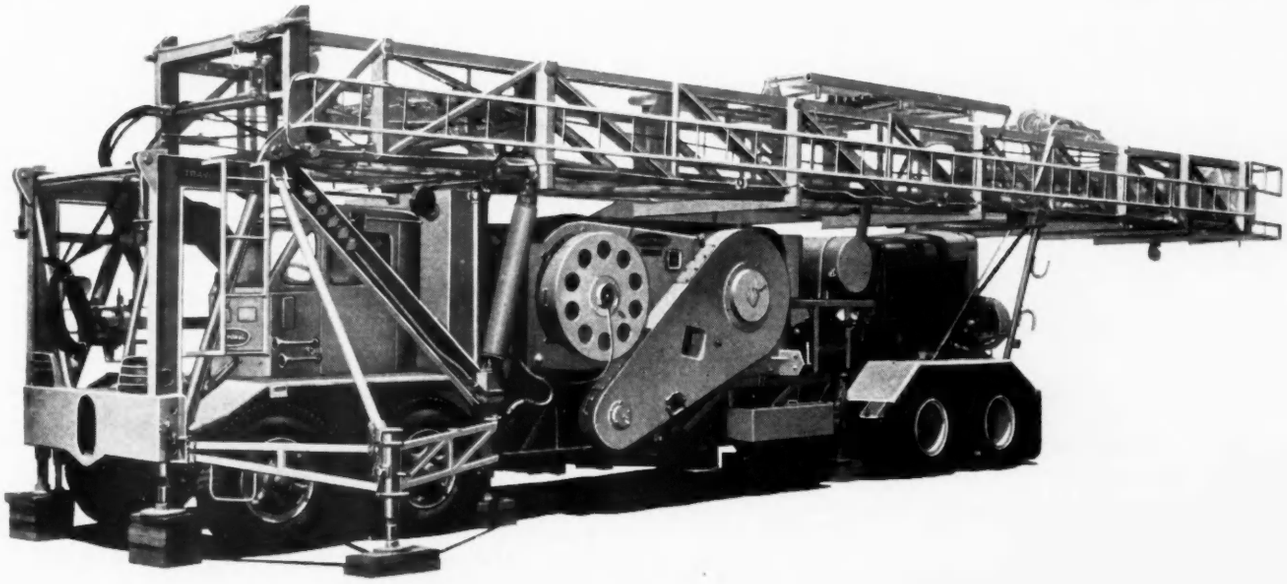


WORKOVER



COMPLETION





Cardwell's KM250 does them all—profitably!

The rugged, powerful KM250 is designed specifically to make a better profit in servicing and workover at the 12,000 to 15,000-foot range—BUT: It has emerged as one of the SPEEDIEST AND MOST MOBILE DRILLING RIGS on the market for profitable drilling at today's footage prices! In the 5,000-foot range—and at even greater depths for slim hole drilling—aggressive contractors have found the KM250 equipped with every modern-day advantage—for cheaper, faster, money-making performance!

OUTPERFORMS THEM ALL!

HIGH MANEUVERABILITY—with fast-spotting drive-in mobility!

40-45 MPH HIGHWAY SPEEDS—and easy and safe to handle!

FAST RIG-UP AND DOWN! Normally needs no external guys for normal conditions! PLUS power to spare! Big, over-size drum brakes. Double-end drum drive. Outboard Fawick clutches. Torque converter drive. Friction engaging clutch on Hydromatic Brake.

SEND FOR "SPECS" TODAY! Write us—right now—for detailed specifications. Just ask for Bulletin No. 3-5-59!

KM250

cardwell

CARDWELL MANUFACTURING COMPANY
BOX 2001 • WICHITA, KANSAS
CABLE: ALLSTEEL • PHONE: Atwood 7-3311

Suppliers' notes

ment the present production of the Bethlehem oil well pumping unit. Initial shipments of pumps are already underway.

Manufacturing of the pumps in Tulsa has meant the installing of a number of modern machine tools and a greater work load for the various departments of the Tulsa plant.

Bethlehem already has an extensive engineering personnel concerned with turnkey and packaged secondary recovery work and the addition of the pump line to the Tulsa plant makes for close liaison between the Sales and Manufacturing Departments.

French Company Formed To Operate Geograph

Formation of a French company to operate the Geograph in Europe and the French Union was announced jointly in Houston and Paris by Robert H. Ray Geophysical Companies and Compagnie Generals de Geophysique of France.

The new company will be known as GEOGRAFRANCE with headquarters in Paris. Charles L. Robinson of Houston will serve as technical director in the Paris office.

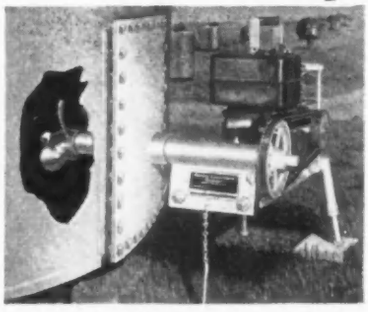
This new jointly owned subsidiary will operate the Geograph in West Germany, Italy, Holland, Belgium, Luxembourg, France and the French Union. Those countries in the French Union are: The Republics of Senegal, Ivory Coast, Dahomey, Haute Volta, Sudan, Nigeria, Congo, Tchad, Gabon, Madagascar, Togo, Guinea, Morocco and Tunisia. Also the Republic of Islamique Mauritanienne, Republic of Central Africa and the State of Cameroun.

New Pittsburgh Office Opened By Halliburton

Halliburton Oil Well Cementing Company operations in Pennsylvania, Ohio, West Virginia, eastern Kentucky and adjoining oil and gas areas are now being supervised from a newly opened office in Pittsburgh.

The new Pittsburgh office, headed by

Now you can get rid of all your BS* at a profit!



NEW Wichita-Smith Tank Agitator makes pipeline oil out of your tank bottoms and saves you money!

This new tank agitator blends **basic sediment* and chemicals quickly and thoroughly . . . settles water and results in up grading oil. The Wichita Propeller Unit is easily welded into position in lower half of manhole plate. One Wichita Power Unit can service any number of tanks. Often eliminates high priced heaters and treaters. Contact your local supply store or . . .

Write today for details!

WICHITA ENGINEERING CO.

3300 Arthur Street Wichita Falls, Texas

NOW.... a UNIVERSAL TREATING COMPOUND!

BrakeSol®

D-7 DEMULSIFIER

Here's a demulsifier that has been tested from Canada to the Gulf with the following advantages:

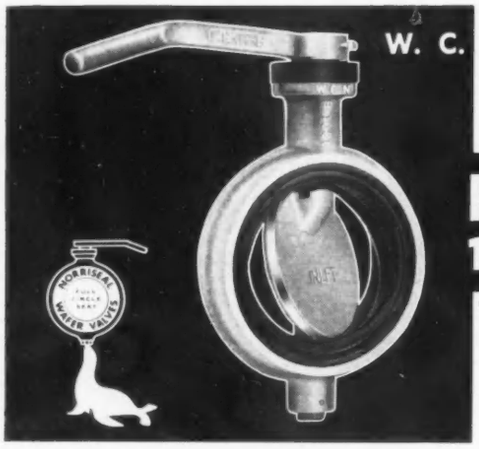
1. UNIVERSAL TREATING COMPOUND . . . successfully treated different types of emulsified conditions in all areas tested.
2. TREATING TEMPERATURES REDUCED . . . reduces vapor losses, conserves gravity. More oil can be sold at better price.
3. CLEANER OIL . . . tank bottoms minimized . . . most cases eliminated.
4. CONTROL OF PARAFFIN AND EMULSION CONDITIONS . . . by mixing BRAKESOL D-7 and PARAFFIN TREATING CHEMICAL.

FOR INFORMATION . . . Contact Supply Store, Brakesol Treating Engineer or write direct!

BrakeSol INC.

P. O. BOX 9506 • OKLAHOMA CITY, OKLA.

EXPORT DISTRIBUTOR: THE NATIONAL SUPPLY CO., EXPORT DIVISION

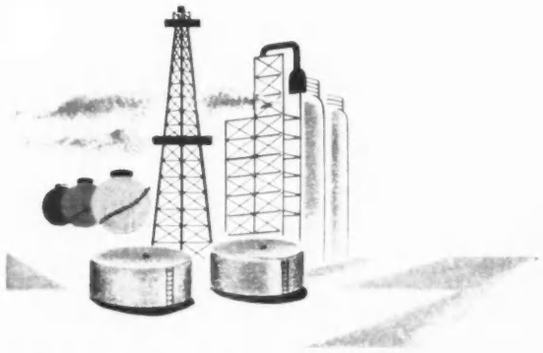


W. C. NORRIS VALVES

Field Tested and Approved

150 psi working pressure

WRITE FOR NEW VALVE BULLETIN
P. O. Box 1739, Tulsa



PETROLEUM INSTALLATIONS

STOP WEEDS

with safe, effective

SIMAZINE *or* ATRAZINE

pre-emergence *pre- or post-emergence*

HERBICIDES

Economical, long residual Geigy herbicides save time and money—do the job right the first time. One application stops weeds before they start—gives you season long control.

Safe to humans and animals, non-irritating to skin, non-flammable, non-corrosive to equipment. Safe to use on valuable land. Available through leading distributors.

FREE BROCHURE: *New full color booklet contains complete directions, diagrams, applications and other useful data for both Simazine and Atrazine.*

MAIL COUPON TODAY

GEIGY AGRICULTURAL CHEMICALS,
Division of Geigy Chemical Corporation
Saw Mill River Road, Ardsley, N.Y., Dept. WO-2

Send free weed control brochure to:

*Name*_____

*Company*_____ *Position*_____

*Address*_____

*City*_____ *State*_____

Geigy *ORIGINATORS OF DDT INSECTICIDES*

Suppliers' notes

Fred Nussbaumer, assistant division manager for the Appalachian area of the company's Evansville, Ind., division, is designed to improve the company's service in the Appalachian and adjoining fields. William W. Ball replaces Nussbaumer at Evansville as division engineer.

ALCOA Predicts Shipments In 1960 to Be History's Largest

Shipments of U. S. produced aluminum during 1960 will be the largest in history, continuing an upward trend which in 1959 saw consumption of the light metal soar nearly 17 percent above the previous record peak established in 1956, according to Frank L. Magee, president of Aluminum Company of America.

Noting in a year-end statement that 1959 domestic industry shipments rocketed to an estimated 4.8 billion pounds, or about 35 percent above those for recession-stricken 1958, Magee expressed an opinion that the gain this year should be in the area of 10 to 15 percent.

Oil Well Supply Is Named Midwest Piping Distributor

Midwest Piping Company, Inc., St. Louis, has announced the appointment of Oil Well Supply Division, U.S. Steel Corporation, as distributor for the Midwest line of welding fittings and flanges for petroleum pipe lines and refinery piping systems.

With main offices in Dallas, Oil Well Supply maintains 30 sales offices and 90 warehouses throughout the United States. Midwest operates two manufacturing plants in St. Louis, two in Houston, and one each in Clifton, N.J., and Los Angeles, producing a comprehensive line of welding fittings and flanges in carbon and alloy steel.

The addition of Oil Well Supply gives Midwest additional national outlets in the oil and gas industry through the widely dispersed facilities of Oil Well Supply.

Parkersburg Rig & Reel Co. Opens Pampa, Texas, Office

The Parkersburg Rig & Reel Company, a Division of Parkersburg-Aetna Corporation, has announced the establishment of a new district sales office in Pampa, Texas.

The new Pampa sales office is staffed by District Salesman Don L. Henry and is a part of the over-all plans of Parkersburg for a continued expansion of all operations in the Panhandle.

Independent Exploration Co., Geophysical Integrators Merge

A merger between the Independent Exploration Company, Houston, and Geophysical Integrators, San Angelo, Texas, has recently been announced by T. I. Harkins, president of the Houston firm and Edward M. Handley, president of the San Angelo firm.

An intensive expansion and research program will be maintained under the new organizational plan, according to Harkins. Handley becomes a vice president of Independent Exploration Company and manager of the Weight Dropping Division with headquarters in San Angelo.

Independent Exploration Company's main offices will remain in Houston. Other offices are located in San Angelo and Fort Worth, Texas; Denver; Calgary, Alberta, Canada; London; Paris; Casablanca, French Morocco; and Algiers.

Western Company Marks 20 Years in Southwest

The Western Company, oil well servicing company with general offices in Fort Worth, recently celebrated 20 years of operation in the southwestern oil fields by a special party which was held at Seagraves, Texas, the original location of the company when it acidized its first well in the Wasson field on August 29, 1939.

The event also served as an open house for the company's new district facilities at Seagraves. On hand to greet guests were H. E. (Eddie) Chiles, president; Walter Beadle, executive vice president; Charles Simmons, Midland Division manager, and other officials and managers of The Western Company. Guests included city and county officials, townspeople and operators from throughout the Permian Basin area.

WORLD OIL'S Trading Post CLASSIFIED ADVERTISING

RATES: Regular Classified (undisplayed) set in this size type: 20 cents per word. Minimum charge $4. Blind box address in our care counts six words. Replies forwarded without charge. Display Classified ads, set in suitably larger type with ruled border, $13.50 per column inch. Ten percent discount for two or more insertions of same copy in consecutive issues. All classified ads payable in advance. Send copy and checks to: Trading Post Classified Section, World Oil. P. O. Box 2608, Houston, Texas.

HELP WANTED

SALESMAN WANTED

Well-established successful firm has opening in an expanding sales department for young man looking for an opportunity in sales work. Must be college graduate, not over 33, in good health, ambitious and not afraid of work. Oil industry experience desirable. The man we are looking for will be trained at home office before moving into sales work on basis of salary plus commission incentive and traveling expenses. Our own personnel know of this advertisement. Your reply will be confidential and should be sufficiently complete to merit contacting you for an interview. Address Box 200-W, WORLD OIL, Houston, Texas.

BUSINESS SERVICE

■ Financial Contacts, Underwriters, Private Brokers reached. No shopping. Confidential. Send details to Consultant—817 - 51st Street, Brooklyn, N. Y.

"Flowers for Thought"

SOUTHWEST FLORIST

Bank of The Southwest Bldg.

Houston, Texas

CA 5-6603

Cable Address:

SOUFLO, Houston, Texas

SITUATIONS WANTED

■ LANDMAN-SCOUT, 42, nine yrs. experience with major, Wyoming and Rocky Mountains. Good Contacts, Desire affiliation with small aggressive company or Independent with Tax Money. Married, Family. Excellent References. Presently employed. Box 207-W, WORLD OIL, Houston, Texas.

FOR SALE

STOCK TO PROMPT DELIVERY

New Tugs 45' - 55' - 65' - 85' - 105'
New Water Taxis 32' - 38' - 40' - 51' - 54'
New Barges 110' and 130'
Floating equipment of all types to our or your specifications.
Also many used items - tugs, barges, yachts and others.

Advise your Needs

EQUITABLE EQUIPMENT CO., INC.
410 Camp St. New Orleans 12, La.

■ **100 Miles 10¾", 307 Wall Pipe. Used, in excellent condition. Immediate delivery. Plain end Machine cleaned, coated. Central Ohio Pipe Co., P. O. Box 5412, Shepherd sta. Columbus, Ohio 3. Phone C.L.36527.**

■ BARGAIN PRICES on Army surplus parts for Failing 314 and Star 71. Transmissions. Rotary hose, V belts, rope sockets, boilers, pump liners and bearing. Truck chains 7:50 x 20 dual wt. 100 lbs. $10.00 pair. Quantity discount. J. Brooke Reed, Fredericktown, Ohio.

■ 3 Cable Tool Rigs for sale or lease. Drilling capacities 3500, 4000 and 4500 feet. Fully equipped, first-class shape. Call Mr. Burris, MU 2-2240, Midland.

■ DRILLING INTEREST OR SALE. 2 Federal Leases, Coconino County, Arizona. One located in T 17N - R 13E—(640 acres). One located in T 17N - R 14E—(586 acres). Send letters of inquiry to Box 209-W, WORLD OIL, Houston, Texas.

OPPORTUNITIES

■ NEW ITEMS WANTED by modern, well established and experienced company with complete development, manufacturing and marketing facilities. Interested in new, patented or patentable oil field specialties or equipment items on royalty basis or outright purchase. Give identification and general use of product in reply to Box 208-W, WORLD OIL, Houston, Texas.

SQUEAKS

From the Bull Wheel

WORLD OIL

"We dropped our string but we're fishing for it now."

He'll Need a Lawyer

Joe: "My uncle tried to make a new kind of a car. He took wheels from a Cadillac, radiator from a Ford, rear lights from a Plymouth—"

Frank: "What did he get?"

Joe: "Two years."

Next Time, 'Mink First'

Did you hear about the girl who would do anything for a mink coat? After she got one she couldn't button it.

Take Your Choice, 'Bub'

A divorcee threatened her ex-husband. "If you miss a single alimony payment, so help me, I'll repossess you!"

Sign Of The Times

When the foreign traveler asked what impressed him most along American highways, he replied:

"Your intriguing signs: First, I noticed 'soft shoulders', then, 'dangerous curves', and 'five gals for a dollar' and after 'try Ethyl' came 'watch out for children'."

Real, Real Gone Man

Two bopsters in a museum spotted a bust of Julius Caesar. One said, "This guy has been gone for 2,000 years."

The other replied, "Crazy man. Those Romans really knew how to live."

If I Could Speak My Mind

A clergyman and truck driver had an automobile crash. The truck driver told the padre what he thought about him in profane terms. When he paused, it was the clergyman's turn.

"You know, my good man, that I cannot indulge in your kind of language, but this much I will tell you; I hope when you go home tonight, your mother will run out from under the porch and bite you."

It's A Sin To Lie

In the early morning spring, the minister was baptizing a new member while his friends looked on. As they stepped out of the water, the friend asked, "Is the water cold, Joe?"

"N-n-o-o-," shivered Joe.

"Better duck him again, Parson," said the friend, "He ain't quite stopped lyin' yet."

Sorry, Bosses' Orders

Steno: "May I have my next week's salary in advance?"

Boss: "No. My wife made me promise not to make advances to you."

Last of the Big Time Spenders

"You say the Scotchman died of apoplexy?"

"Yep. He was throwing pennies to the kids from his window, and the string broke."

Clever, Eh What, These K-9s

I've got a dog named "Louise" and he sure is smart. One day he saw a sign that read "Wet Paint" and he did.

No, But I'm Thinkin'

Policeman: "Look here, have you any explanation for wandering around the streets at this hour of the night?"

Reveler: "Listen, if I had an explanation, I'd have gone home to my wife hours ago."

Doghouse Resident

Husband: "OK, Joe, you asked me why I am in the doghouse, so I'll tell you. You see, last week I submitted an article to Robert Ripley and by mistake my wife's picture got into the wrong envelope."

Joe: "So, why does that make you in the doghouse?"

Husband: "Because, Robert Ripley sent her picture back with a note reading, "I Don't Believe It!"

State of the Union

There's one thing you can say for the men who run our government from time to time. They're running it like nobody's business!

It's as Clear as Mud

The difference between a neurotic, a psychotic and a psychiatrist: The neurotic builds castles in the air, the psychotic lives in them, and the phychiatrist collects rent on them.

1960 OIL DIRECTORIES

19 pocket-size, plastic-bound personnel directories covering the entire oil industry of the world, from top executives to foremen. Over 135,000 key men are listed. First seven books cover Producing and Drilling Contracting.

We Send Our Directories on Approval

1. Texas
2. Oklahoma
3. California
4. Kansas
5. Mich.-Ill.-Ind.-Ky.
6. La.-Ark.-Miss.-Ga.-Fla.
7. Rocky Mountain Region and New Mexico
8. Oil Well Drilling Contractors (Covers the World)
9. Secondary Recovery and Offshore Operations
10. Refining, Petrochemical, and Natural Gas Processing Plants of the World
11. Pipe Line Companies and Pipe Line Contractors (Covers the World)
12. Oil Directory of Companies Outside the U. S. A. and Canada
13. Oil Directory of Canada
14. Directory of Geophysical and Oil Companies Who Use Geophysical Service
15. Directory of Oil Well Supply Companies (Covers the World)
16. Oil Directory of Houston, Texas
17. Oil Directory of Tulsa
18. Oil Directory of Alaska
19. Oil Directory of Consulting Engineers

MIDWEST OIL REGISTER, INC.

DRAWER 7248, TULSA, OKLAHOMA

C. L. Cooper, Publisher

SECONDARY RECOVERY

PETROLEUM ENGINEERS
STEPHENS ENGINEERING
WICHITA FALLS, TEXAS

RESERVOIR ENGINEERING

Water Flooding Gas Repressuring

EVALUATION CORE ANALYSIS

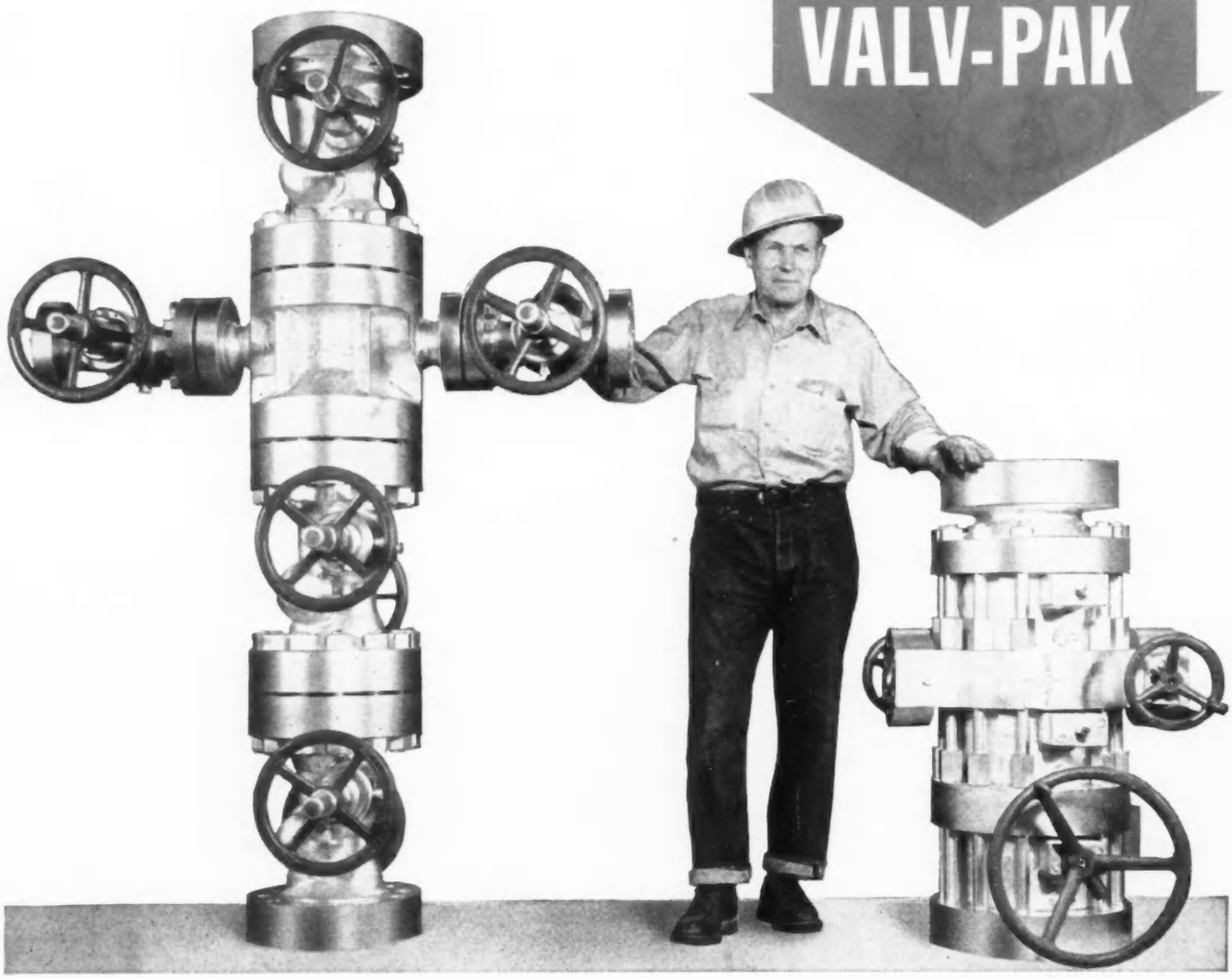
SURVEYS ECONOMICS

Cost Estimates, Design, Installation

FIELD SUPERVISION

Phone 723-2167

new GROVE VALV-PAK



A MAJOR ACHIEVEMENT IN COMPACT, VERSATILE CHRISTMAS TREE VALVE ASSEMBLIES

Maximum Flexibility! —Only Grove Valv-Pak design permits field rearrangement of valves as your well characteristics change. Individual components that must be replaced due to erosion or corrosion can be changed in the field, eliminating replacement of the whole tree, as is necessary in multiple combination units.

Compact! —Amazing vertical and horizontal compactness and lighter weight make Grove Valv-Pak handier, faster and easier to install than conventional units.

"Right Now" Delivery on Custom Units—Grove's unique design permits rapid assembly of custom units to meet your critical completion schedules on time.